MILLSTONE NUCLEAR POWER STATION
UNIT 2

TECHNICAL SPECIFICATIONS

AUG 1 1975

APPENDIX "A"
TO
LICENSE NO. DPR - 65

ISSUED BY THE UNITED STATES NUCLEAR REGULATORY COMMISSION

MILLSTONE NUCLEAR POWER STATION

UNIT 2

TECHNICAL SPECIFICATIONS

APPENDIX "A"

TO

LICENSE NO. DPR-65

INDEX

DEFINITIONS

DEFINITIONS

INDEX

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

BASES

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITION FOR OPERATION AND SURVEILLANCE REQUIREMENTS

BASES

BASES

BASES

DESIGN FEATUTRES

ADMINISTRATIVE CONTROLS

ADMINISTRATIVE CONTROLS

ADMINISTRATIVE CONTROLS

SECTION 1.0

DEFINITIONS

1.0 DEFINITIONS

DEFINED TERMS

1.1 The DEFINED TERMS of this section appear in capitalized type and are applicable throughout these Technical Specifications.

THERMAL POWER

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

RATED THERMAL POWER

1.3 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 2700 MWt.

OPERATIONAL MODE

1.4 An OPERATIONAL MODE shall correspond to any one inclusive combination of core reactivity condition, power level, and average reactor coolant temperature specified in Table 1.1.

ACTION

1.5 ACTION shall be those additional requirements specified as corollary statements to each principal specification and shall be part of the specifications.

OPERABLE - OPERABILITY

1.6 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, normal and emergency electrical power sources, 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).

REPORTABLE EVENT

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

CONTAINMENT INTEGRITY

1.8 CONTAINMENT INTEGRITY shall exist when:

1.8.1 All penetrations required to be closed during accident conditions are either:

a) Capable of being closed by an OPERABLE containment automatic isolation valve system,* or

b) Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except for valves that are open under administrative control as permitted by Specification 3.6.3.1,

1.8.2 The equipment hatch is closed and sealed, and

1.8.3 The airlock is in compliance with the requirements of Specification 3.6.1.3.

CHANNEL CALIBRATION

1.9 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

1.10 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

1.11 A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated signal into the channel as close to the primary sensor as practicable to verify OPERABILITY including alarm and/or trip functions.

---

* In MODE 4, the requirement for an OPERABLE containment automatic isolation valve system is satisfied by use of the containment isolation trip pushbuttons.

CORE ALTERATION

1.12 CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.

SHUTDOWN MARGIN

1.13 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all control element assemblies (shutdown and regulating) are fully inserted except for the single assembly of highest reactivity worth which is assumed to be fully withdrawn.

IDENTIFIED LEAKAGE

1.14 IDENTIFIED LEAKAGE shall be:

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

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

UNIDENTIFIED LEAKAGE

1.15 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE or CONTROLLED LEAKAGE.

PRESSURE BOUNDARY LEAKAGE

1.16 PRESSURE BOUNDARY LEAKAGE shall be leakage (except steam generator tube leakage) through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall.

CONTROLLED LEAKAGE

1.17 CONTROLLED LEAKAGE shall be the water flow from the reactor coolant pump seals.

AZIMUTHAL POWER TILT - T_q

1.18 AZIMUTHAL POWER TILT shall be the difference between the maximum power generated in any core quadrant (upper or lower) and the average power of all quadrants in that half (upper or lower) of the core divided by the average power of all quadrants in that half (upper or lower) of the core.

$$\text{AZIMUTHAL POWER TILT} = \left[\frac{\text{Maximum power in any core quadrant (upper or lower)}}{\text{Average power of all quadrants (upper or lower)}}\right] - 1$$

DOSE EQUIVALENT I-131

1.19 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcurie/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 Regulatory Guide 1.109 REv. 1, "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."

$\bar{E}$-AVERAGE DISINTEGRATION ENERGY

1.20 $\bar{E}$ shall be the average sum of the beta and gamma energies per disintegration (in MEV) for isotopes, other than iodines, with half lives greater than 15 minutes, making up at least 95% of the total noniodine activity in the coolant.

STAGGERED TEST BASIS

1.21 A STAGGERED TEST BASIS shall consist of:

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

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

FREQUENCY NOTATION

1.22 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.2.

AXIAL SHAPE INDEX

1.23 The AXIAL SHAPE INDEX (Y_E) used for normal control and indication is the power level detected by the lower excore nuclear instrument detectors (L) less the power level detected by the upper excore nuclear instrument detectors (U) divided by the sum of these power levels. The AXIAL SHAPE INDEX (Y_I) used for the trip and pretrip signals in the reactor protection system is the above value (Y_E) modified by an appropriate multiplier (A) and a constant (B) to determine the true core axial power distribution for that channel.

$$Y_E = \frac{L-U}{L+U} \qquad Y_I = AY_E + B$$

CORE OPERATING LIMITS REPORT

1.24 The CORE OPERATING LIMITS REPORT is the unit specific document that provides the core operating limits for the current operating reload cycle. These cycle specific core operating limits shall be determined for each reload cycle in accordance with Specification 6.9.1.8. Plant operation within these operating limits is addressed in individual specifications.

ENCLOSURE BUILDING INTEGRITY - DELETED

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the CEA drive mechanism.

ENGINEERED SAFETY FEATURE RESPONSE TIME

1.27 The ENGINEERED SAFETY FEATURE RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of

ENGINEERED SAFETY FEATURE RESPONSE TIME (Continued)

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.

PHYSICS TESTS

1.28 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 13.0 of the FSAR, 2) authorized under the provisions of 10 CFR 50.59, or 3) otherwise approved by the Commission.

TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR - F^T_r

1.29 The TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR is the ratio of the peak pin power to the average pin power in an unrodded core. This value includes the effect of AZIMUTHAL POWER TILT.

SOURCE CHECK

1.30 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to radiation.

PURGE - PURGING

1.34 PURGE or PURGING 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 required to purify the containment.

TABLE 1.1

OPERATIONAL MODES

MODE	REACTIVITY CONDITION, K_{eff}	% RATED THERMAL POWER*	AVERAGE COOLANT TEMPERATURE
1. POWER OPERATION	$\geq$ 0.99	> 5%	$\geq$ 300°F
2. STARTUP	$\geq$ 0.99	$\leq$ 5%	$\geq$ 300°F
3. HOT STANDBY	< 0.99	0	$\geq$ 300°F
4. HOT SHUTDOWN	< 0.99	0	300°F > T_{avg} > 200°F
5. COLD SHUTDOWN	< 0.98	0	$\leq$ 200°F
6. REFUELING**	$\leq$ 0.95	0	$\leq$ 140°F

*Excluding decay heat.

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

VENTING

1.35 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.

MEMBER(S) OF THE PUBLIC

1.36 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 its 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.

The term "REAL MEMBER OF THE PUBLIC" means an individual who is exposed to existing dose pathways at one particular location.

SITE BOUNDARY

1.37 The SITE BOUNDARY shall be that line beyond which the land is not owned, leased or otherwise controlled by the licensee.

UNRESTRICTED AREA

1.38 An UNRESTRICTED AREA shall be any area at or beyond the site boundary to which access 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 industrial, commercial institutional and/or recreational purposes.

STORAGE PATTERN

1.39 The Region B spent fuel racks contain a cell blocking device in every 4th rack location for administrative control. This 4th location will be referred to as the blocked location. A STORAGE PATTERN refers to a blocked location and all adjacent and diagonal cell locations surrounding the blocked location within the respective region.

TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	Once per 12 hours.
D	Once per 24 hours.
W	Once per 7 days.
M	Once per 31 days.
Q	Once per 92 days.
SA	Once per 6 months.
R	Once per 18 months.
S/U	Prior to each reactor startup.
P	Prior to each release.
N.A.	Not applicable.

Correction letter of 8-17-95

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and maximum cold leg coolant temperature shall not exceed the limits shown on Figure 2.1-1.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of maximum cold leg temperature and THERMAL POWER has exceeded the appropriate pressurizer pressure line, be in HOT STANDBY within 1 hour.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2750 psia.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.

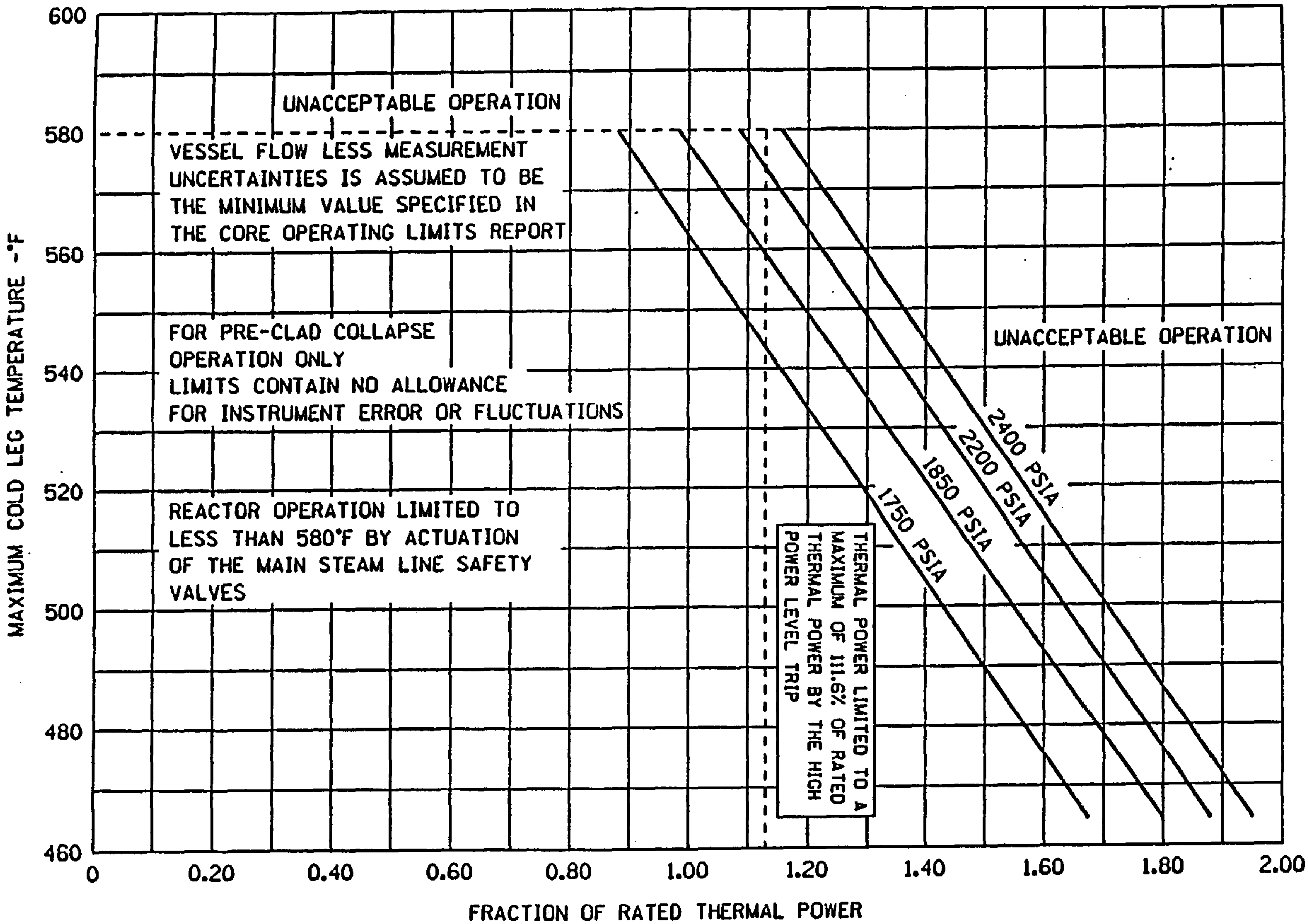


FIGURE 2.1-1
REACTOR CORE THERMAL MARGIN SAFETY LIMIT-
FOUR REACTOR COOL PUMPS OPERATING

SKM-MCR- 1gn

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SETPOINTS

2.2.1 The reactor protective instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: AS SHOWN FOR EACH CHANNEL IN TABLE 3.3-1.

ACTION:

With a reactor protective instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

0809

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

	FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1.	Manual Reactor Trip	Not Applicable	Not Applicable
2.	Power Level-High		
	Four Reactor Coolant Pumps Operating	$\leq$ 9.6% above THERMAL POWER, with a minimum setpoint of $\leq$ 14.6% of RATED THERMAL POWER, and a maximum of $\leq$ 106.6% of RATED THERMAL POWER.	$\leq$ 9.7% Above THERMAL POWER, with a minimum of $\leq$ 14.7% of RATED THERMAL POWER, and a maximum of $\leq$ 106.7% of RATED THERMAL POWER.
3.	Reactor Coolant Flow - Low (1)	$\geq$ 91.7% of reactor coolant flow with 4 pumps operating*.	$\geq$ 90.9% of reactor coolant flow with 4 pumps operating.
4.	DELETED		
5.	Pressurizer Pressure - High	$\leq$ 2397 psia	$\leq$ 2407 psia
6.	Containment Pressure - High	$\leq$ 4.42 psig	$\leq$ 5.07 psig
7.	Steam Generator Pressure - Low (2) (5)	$\geq$ 691 psia	$\geq$ 677 psia
8.	Steam Generator Water Level - Low (5)	$\geq$ 48.5% Water Level - each steam generator	$\geq$ 47.5% Water Level - each steam generator
9.	Local Power Density - High (3)	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2 (4).	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2 (4).

*Design Reactor Coolant flow with 4 pumps operating is the lesser of either:
a. The reactor coolant flow rate measured per Specification 4.2.6.1, or
b. The minimum value specified in the CORE OPERATING LIMITS REPORT.

TABLE 2

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
10. Thermal Margin/Low Pressure (1)		
Four Reactor Coolant Pumps Operating	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4 (4).	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4 (4).
11. Loss of Turbine--Hydraulic Fluid (3) Pressure - Low	≥ 500 psig	≥ 500 psig
12. Wide Range Logarithmic Neutron Flux Monitor - Shutdown	Not Applicable	Not Applicable
13. Reactor Protection System Logic Matrices	Not Applicable	Not Applicable
14. Reactor Protection System Logic Matrix Relays	Not Applicable	Not Applicable
15. Reactor Trip Breakers	Not Applicable	Not Applicable

TABLE NOTATION

(1) Trip may be bypassed below 5% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is ≥ 5% of RATED THERMAL POWER.

(2) Trip may be manually bypassed when steam generator pressure is < 800 psia and all CEAs are fully inserted; bypass shall be automatically removed when steam generator pressure is ≥ 800 psia.

(3) Trip may be bypassed below 15% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is ≥ 15% of RATED THERMAL POWER.

(4) Calculations of the trip setpoint includes measurements, calculational and processor uncertainties, and dynamic allowances.

(5) Each of four channels actuate on the auctioneered output of two transmitters, one from each steam generator.

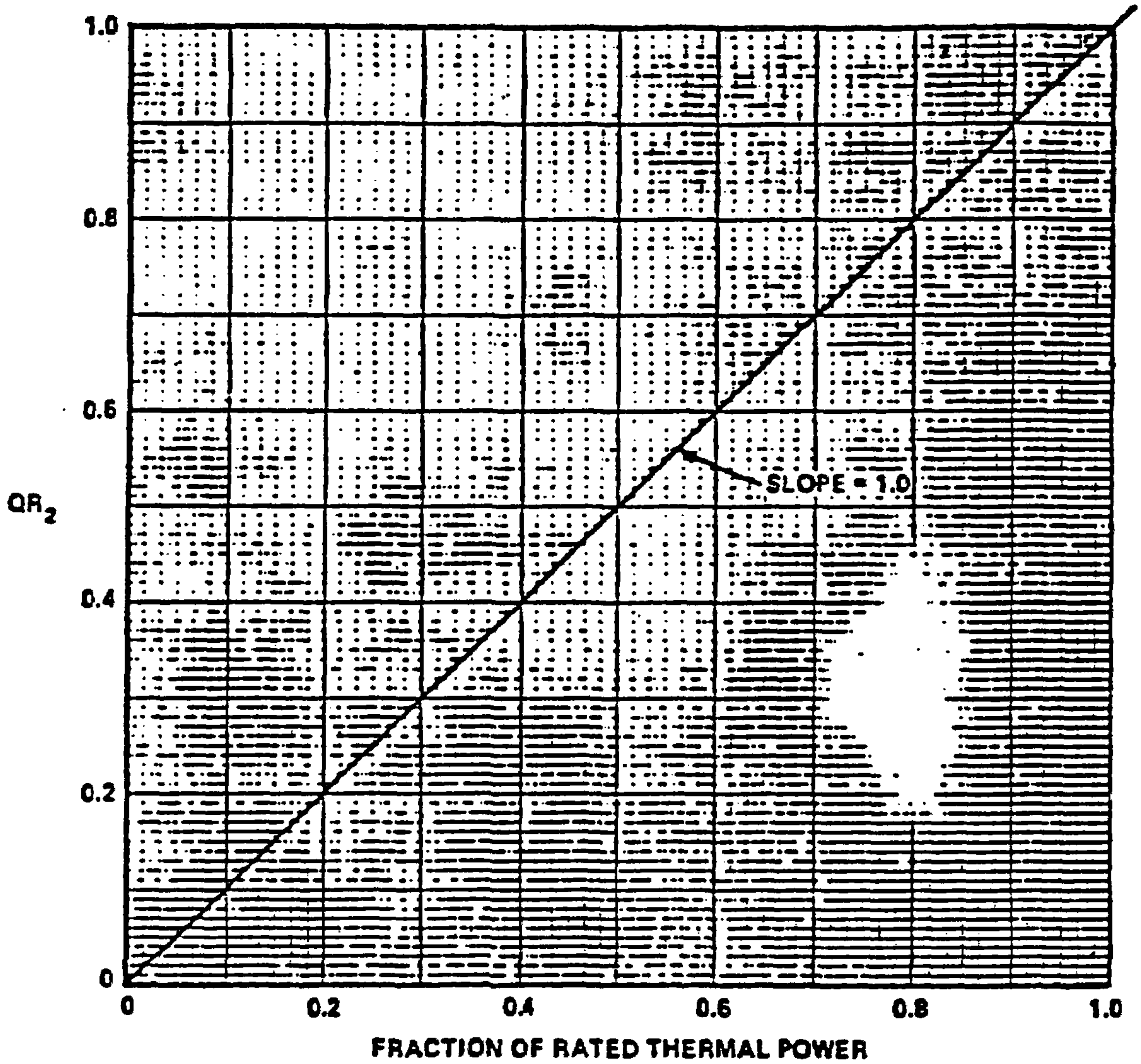


FIGURE 2.2-1

Local Power Density — High Trip Setpoint
Part 1 (Fraction of RATED THERMAL POWER Versus QR_2)

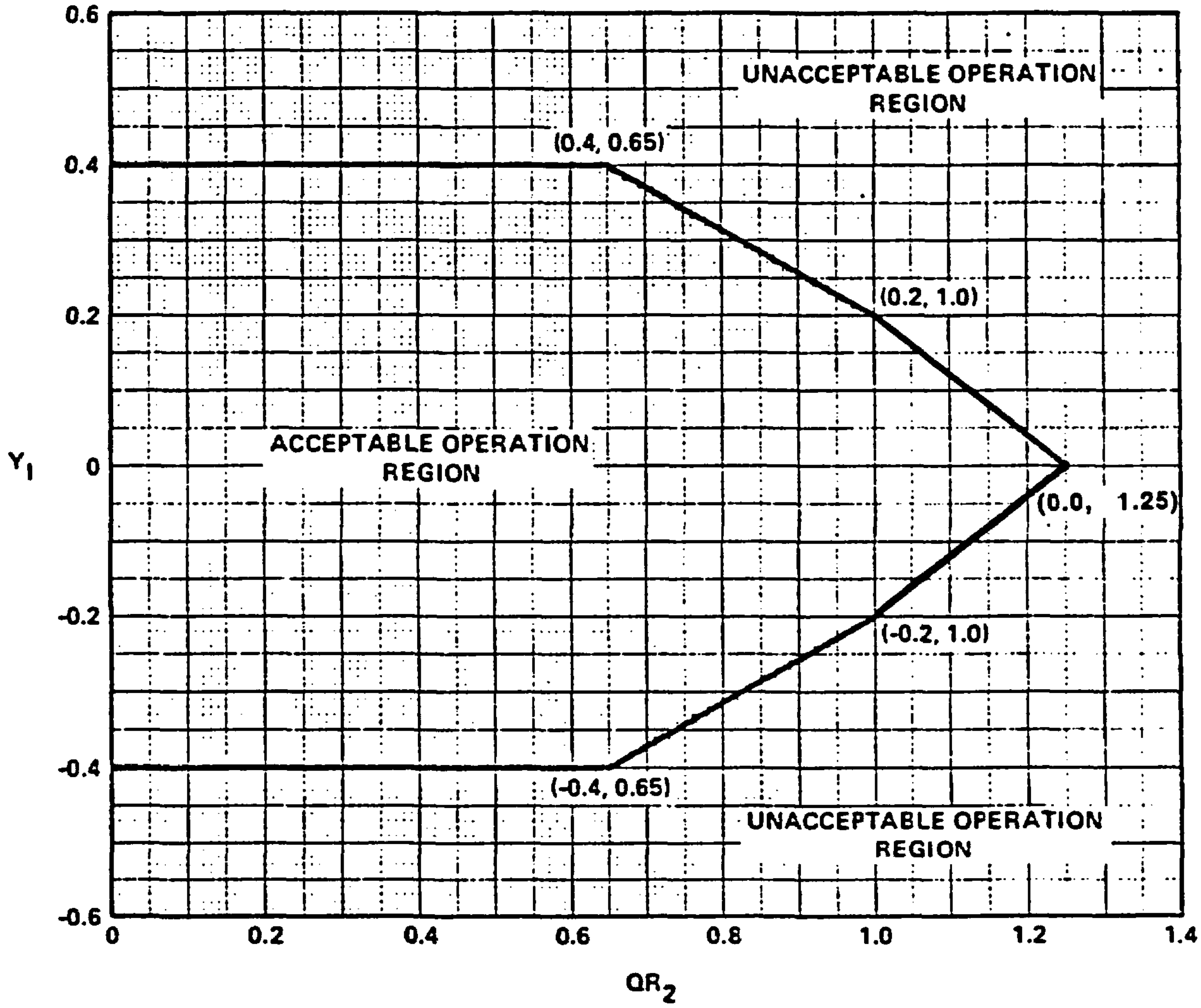


FIGURE 2.2-2 Local Power Density – High Trip Setpoint Part 2 (QR_2 Versus Y_I)

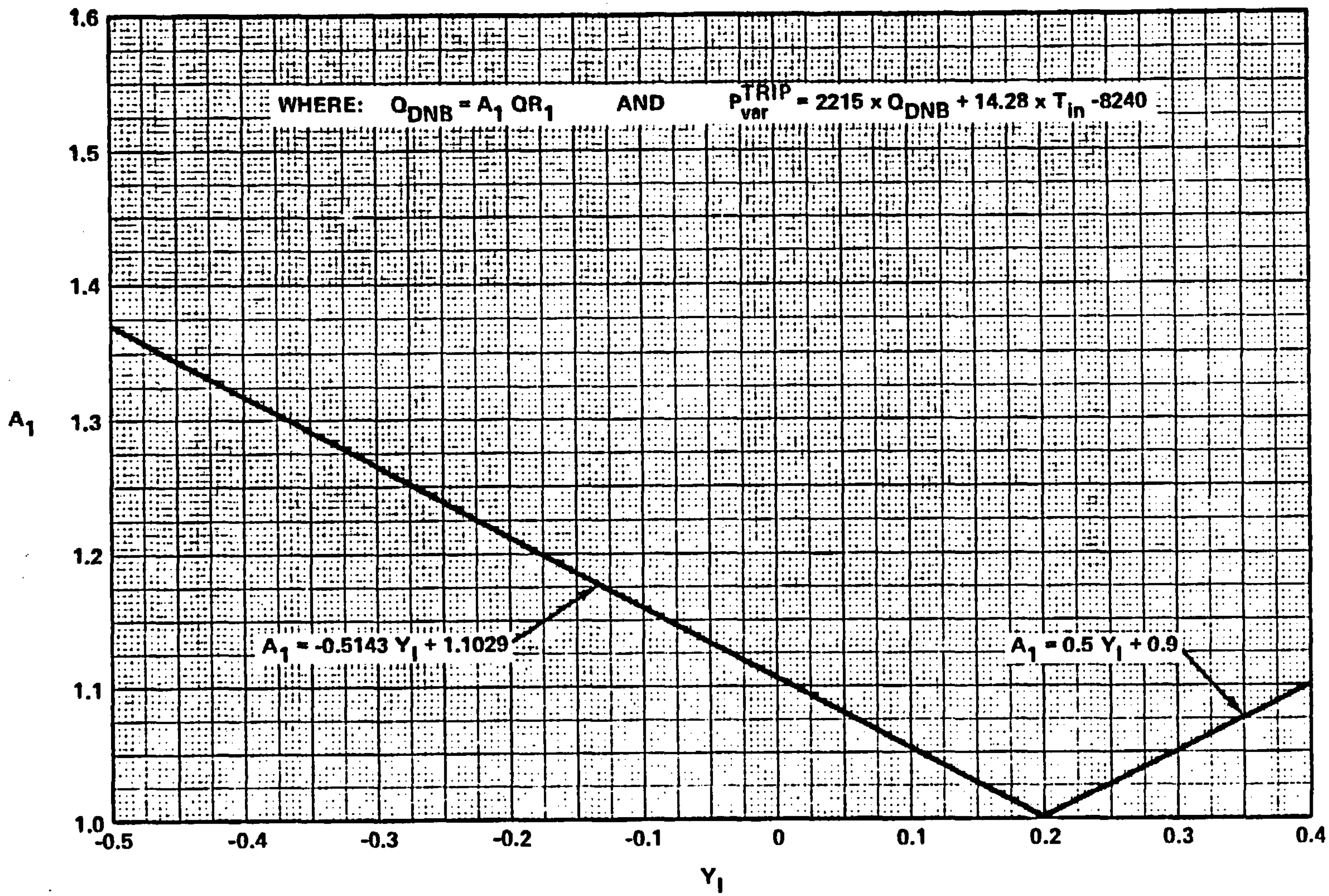


FIGURE 2.2-3 Thermal Margin/Low Pressure Trip Setpoint Part 1 (Y_I Versus A_1)

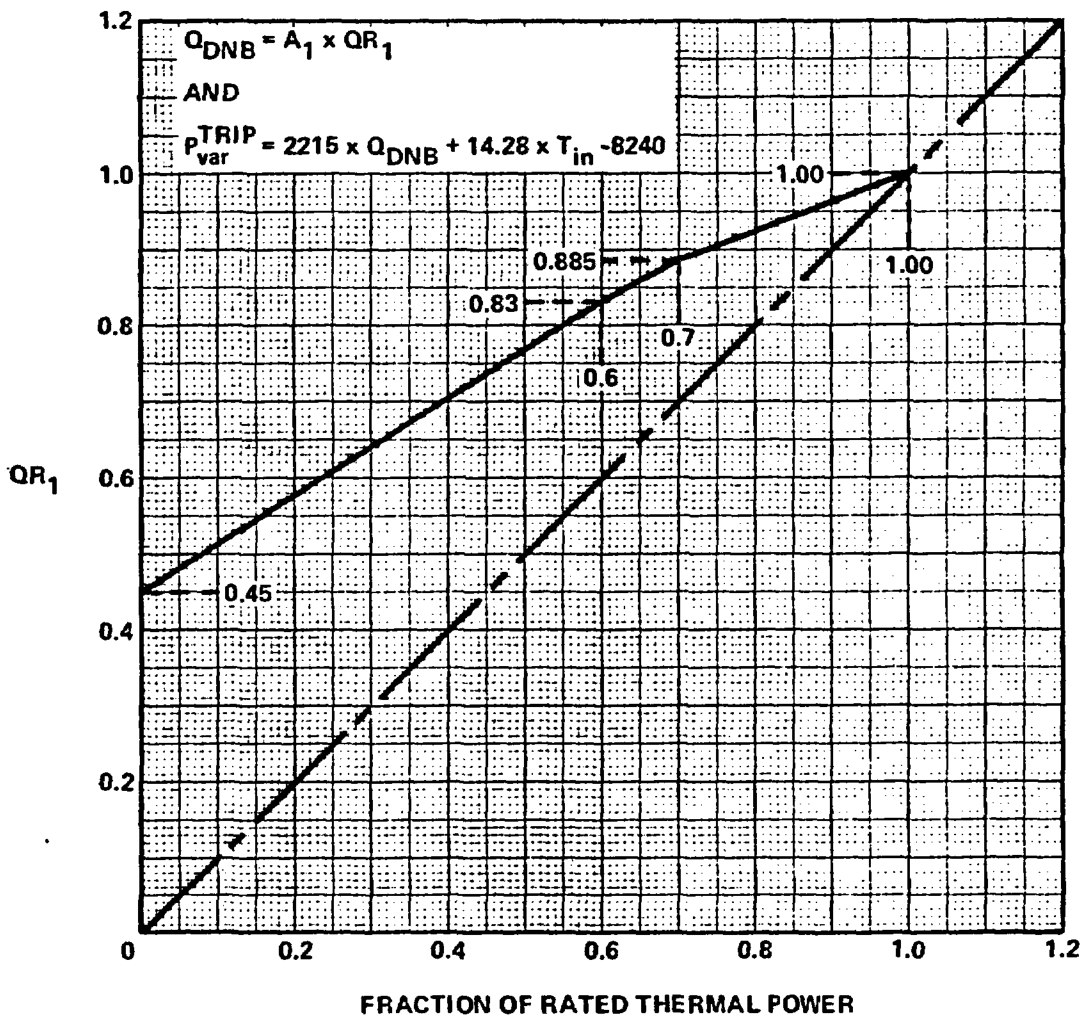


FIGURE 2.2-4 Thermal Margin/Low Pressure Trip Setpoint (Part 2 Fraction of RATED THERMAL POWER Versus QR_1)

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

2.1.1 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel cladding and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate at or less than the fuel centerline melt linear heat rate limit. Centerline fuel melting will not occur for this peak linear heat rate. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through the HTP correlation. The HTP DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, DNBR, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The value of the DNBR during steady state operation, normal operational transients, and anticipated transients is limited to be no less than the DNB correlation limit. The correlation limit corresponds to a 95 percent probability at a 95 percent confidence level (i.e., 95/95 limit) that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and maximum cold leg temperature with four Reactor Coolant Pumps operating for which the minimum DNBR is no less than the 95/95 limit for the DNB correlation. The limits in Figure 2.1-1 were calculated for reactor coolant inlet temperatures less than or equal to 580°F. The dashed line at 580°F coolant inlet temperatures is not a safety limit; however, operation above 580°F is not possible because of the actuation of the main steam line safety valves which limit the maximum value of reactor inlet temperature. Reactor operation at THERMAL POWER levels higher than 111.6% of RATED THERMAL POWER is prohibited by the high power level trip setpoint specified in Table 2.2-1. The area of safe operation is below and to the left of these lines.

Bases Change

THIS PAGE INTENTIONALLY LEFT BLANK.

The conditions for the Thermal Margin Safety Limit curves in figure 2.1-1 to be valid are shown on the figure.

The reactor protective system in combination with the Limiting Conditions for Operation, is designed to prevent any anticipated combination of transient conditions for reactor coolant system temperature, pressure, and THERMAL POWER level that would result in a DNBR below the 95/95 limit for DNB correlation. and preclude the existence of flow instabilities.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor pressure vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plant Components which permits a maximum transient pressure of 110% (2750 psia) of design pressure. The Reactor Coolant System piping, valves and fittings, are designed to ANSI B31.7, Class I which permits a maximum transient pressure of 110% (2750 psia) of component design pressure. The Safety Limit of 2750 psia is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at 3125 psia to demonstrate integrity prior to initial operation.

PTSCR 2-3-00
February 25, 2000

2.2.1 REACTOR TRIP SET POINTS

The Reactor Trip Setpoints specified in Table 2.2-1 are the values at which the Reactor Trips are set for each parameter. The Trip Values have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their safety limits. Operation with a Trip Setpoint less conservative than its setpoint but within its specified Allowable Value is acceptable on the basis that each Allowable Value is equal to or less than the drift allowance assumed to occur for each trip used in the accident analyses.

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Power Level-High

The Power Level-High trip provides reactor core protection against reactivity excursions which are too rapid to be protected by a Pressurizer Pressure-High or Thermal Margin/Low Pressure trip.

The Power Level-High trip setpoint is operator adjustable and can be set no higher than 9.6% above the indicated THERMAL POWER level. Operator action is required to increase the trip setpoint as THERMAL POWER is increased. The trip setpoint is automatically decreased as THERMAL POWER decreases. The trip setpoint has a maximum value of 106.6% of RATED THERMAL POWER and a minimum setpoint of 14.6% of RATED THERMAL POWER. Adding to this maximum value the possible variation in trip point due to calibration and instrument errors, the maximum actual steady-state THERMAL POWER level at which a trip would be actuated is 111.6% of RATED THERMAL POWER, which is the value used in the accident analyses.

Reactor Coolant Flow-Low

The Reactor Coolant Flow-Low trip provides core protection to prevent DNB in the event of a sudden significant decrease in reactor coolant flow.

Revised by NRC letter dated October 4, 2001
(Bases Change)

Reactor Coolant Flow-Low (Continued)

The low-flow trip setpoint and Allowable Value have been derived in consideration of instrument errors and response times of equipment involved to maintain the DNBR above the 95/95 limit for the DNB correlation under normal operation and expected transients.

Pressurizer Pressure-High

The pressurizer Pressure-High trip, backed up by the pressurizer code safety valves and main steam line safety valves, provides reactor coolant system protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is approximately 100 psi below the nominal lift setting (2500 psia) of the pressurizer code safety valves and its concurrent operation with the power-operated relief valves avoids the undesirable operation of the pressurizer code safety valves.

Containment Pressure-High

The Containment Pressure-High trip provides assurance that a reactor trip is initiated concurrently with a safety injection. The setpont for this trip is identical to the safety injection setpoint.

Steam Generator Pressure-Low

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators and subsequent cooldown of the reactor coolant. The trip setting is sufficiently below the full-load operating point so as not to interfere with normal operation, but still high enough to provide the required protection in the event of excessively high steam flow.

Bases Change

Steam Generator Water Level - Low

The Steam Generator Water Level-Low Trip provides core protection by preventing operation with the steam generator water level below the minimum volume required for adequate heat removal capacity and assures that the design pressure of the reactor coolant system will not be exceeded.

Local Power Density-High

The Local Power Density-High trip, functioning from AXIAL SHAPE INDEX monitoring, is provided to ensure that the peak local power density in the fuel which corresponds to fuel centerline melting will not occur as a consequence of axial power maldistributions. A reactor trip is initiated whenever the AXIAL SHAPE INDEX exceeds the allowable limits of Figure 2.2-2. The AXIAL SHAPE INDEX is calculated from the upper and lower ex-core neutron detector channels. The calculated setpoints are generated as a function of THERMAL POWER level. The trip is automatically bypassed below 15 percent power as sensed by the power range nuclear instrument Level 1 bistable.

The maximum AZIMUTHAL POWER TILT and maximum CEA misalignment permitted for continuous operation are assumed in generation of the setpoints. In addition, CEA group sequencing in accordance with the Specifications 3.1.3.5 and 3.1.3.6 is assumed. Finally, the maximum insertion of CEA banks which can occur during any anticipated operational occurrence prior to a Power Level-High trip is assumed.

Thermal Margin/Low Pressure

The Thermal Margin/Low Pressure trip is provided to prevent operation when the DNBR is below the 95/95 limit for the DNB correlation.

Thermal Margin/Low Pressure (Continued)

The trip is initiated whenever the reactor coolant system pressure signal drops below either 1865 psia or a computed value as described below, whichever is higher. The computed value is a function of the higher of ΔT power or neutron power, reactor inlet temperature, the number of reactor coolant pumps operating and the AXIAL SHAPE INDEX. The minimum value of reactor coolant flow rate, the maximum AZIMUTHAL POWER TILT and the maximum CEA deviation permitted for continuous operation are assumed in the generation of this trip function. In addition, CEA group sequencing in accordance with Specifications 3.1.3.5 and 3.1.3.6 is assumed. Finally, the maximum insertion of CEA banks which can occur during any anticipated operational occurrence prior to a Power Level-High trip is assumed.

Thermal Margin/Low Pressure trip setpoints are derived from the core safety limits. A safety margin is provided which includes allowances for equipment response times, core power, RCS temperature, and pressurizer pressure measurement uncertainties, processing errors, and a further allowance to compensate for the time delay associated with providing effective termination of the occurrence that exhibits the most rapid decrease in margin to the safety limit.

Loss of Turbine

A Loss of Turbine trip causes a direct reactor trip when operating above 15% of RATED THERMAL POWER as sensed by the power range nuclear instrument Level 1 bistable. This trip provides turbine protection, reduces the severity of the ensuring transient and helps avoid the lifting of the main steam line safety valves during the ensuing transient, thus extending the service life of these valves. No credit was taken in the accident analyses for operation of this trip. Its functional capability at the specified trip setting is required to enhance the overall reliability of the Reactor Protection System.

The Wide Range Logarithmic Neutron Flux Monitor - Shutdown, Reactor Protection System Logic Matrices, Reactor Protection System Logic Matrix Relays, and Reactor Trip Breakers functional units are components of the Reactor Protective System for which OPERABILITY requirements are provided within the Technical Specifications (see Technical Specification 3.3.1.1, "Reactor Protective Instrumentation"). These functional units do not have specific trip setpoints or allowable values, similar to the manual reactor trip functional unit. However, these functional units are provided here for completeness and consistency with the RPS Instrumentation identified in Technical Specification 3.3.1.1.

DELETED

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 MODES 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, except as provided in LCO 3.0.6. 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 a MODE in which the specification does not apply by placing it, as applicable, in:

1. At least HOT STANDBY 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 it is identified that a Limiting Condition for Operation is not met. Exceptions to these requirements are stated in the individual specifications.

This specification is not applicable in MODES 5 or 6.

3.0.4 Entry into an OPERATIONAL MODE or other specified condition shall not be made when the conditions for the Limiting Condition for Operation are not met and the associated ACTION requires a shutdown if they are not met within a specified time interval. Entry into an OPERATIONAL MODE or specified condition may be made in accordance with ACTION requirements when conformance to them permits continued operation of the facility for an unlimited period of time. This provision shall not prevent passage through or to OPERATIONAL MODES as required to comply with ACTION requirements.

3.0.5 When a system, subsystem, train, component or device is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered OPERABLE for the purpose of satisfying the requirements of its applicable Limiting Condition for Operation, provided: (1) its corresponding normal or emergency power source is OPERABLE; and (2) all of its redundant system(s), subsystem(s), train(s), component(s) and device(s) are OPERABLE, or likewise satisfy the requirements of this specification. Unless both conditions (1) and (2) are satisfied within 2 hours, ACTION shall be initiated to place the unit in a MODE in which the applicable Limiting Condition for Operation does not apply by placing it, as applicable, in:

1. At least HOT STANDBY 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.

This specification is not applicable in MODES 5 or 6.

3.0.6 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

SURVEILLANCE REQUIREMENTS

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

Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the Limiting Condition for Operation. Failure to perform a Surveillance within the specified surveillance interval shall be failure to meet the Limiting Condition for Operation except as provided in Specification 4.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with a maximum allowable extension not to exceed 25% of the surveillance time interval.

4.0.3 If it is discovered that a Surveillance was not performed within its specified surveillance interval, then compliance with the requirement to declare the Limiting Condition for Operation not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified surveillance interval, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the Limiting Condition for Operation must immediately be declared not met, and the applicable Condition(s) must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the Limiting Condition of Operation must immediately be declared not met, and the applicable Condition(s) must be entered.

4.0.4 Entry into an OPERATIONAL MODE or other specified condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the stated surveillance interval or as otherwise specified. This provision shall not prevent passage through or to OPERATIONAL MODES as required to comply with ACTION requirements.

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

a. Inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing 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.

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 ainspection 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
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

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 REACTVITY CONTROL SYSTEMS

3/4.1.1 REACTIVITY CONTROL SYSTEMS

SHUTDOWN MARGIN - (SDM)

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be within the limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: MODES 3[1], 4 and 5.

ACTION:

With the SHUTDOWN MARGIN not within the limit specified in the CORE OPERATING LIMITS REPORT, within 15 minutes, initiate and continue boration at ≥ 40 gpm of boric acid solution at or greater than the required refueling water storage tank (RWST) concentration (ppm) until the SHUTDOWN MARGIN is restored to within limit.

SURVEILLANCE REQUIREMENT

4.1.1.1 Verify SHUTDOWN MARGIN is within the limit specified in the CORE OPERATING LIMITS REPORT at least once every 24 hours.

[1] See Special Test Exception 3.10.1

"This page left intentionally blank."

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 REACTIVITY CONTROL SYSTEMS

REACTIVITY BALANCE

LIMITING CONDITION FOR OPERATION

3.1.1.2 The core reactivity balance shall be within $\pm$ 1% $\Delta k/k$ of predicted values.

APPLICABILITY: MODES 1 and 2.

ACTION:

With core reactivity balance not within limit:

Re-evaluate core design and safety analysis and determine that the reactor core is acceptable for continued operation and establish appropriate operating restrictions and Surveillance Requirements within 7 days or otherwise be in MODE 3 within the next 6 hours.

SURVEILLANCE REQUIREMENT

4.1.1.2 Verify[1] overall core reactivity balance is within $\pm$ 1% $\Delta k/k$ of predicted values prior to entering MODE 1 after fuel loading and at least once every 31 Effective Full Power Days[2]. The provisions of Specification 4.0.4 are not applicable.

(1) The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

(2) Only required after 60 Effective Full Power Days.

BORON DILUTION

LIMITING CONDITION FOR OPERATION

3.1.1.3 The following boron dilution restrictions shall be met:

a. The flow rate of reactor coolant through the core shall be ≥ 1000 gpm whenever a reduction in Reactor Coolant System boron concentration is being made.

b. A maximum of two charging pumps shall be capable of injecting into the Reactor Coolant System whenever the temperature of one or more of the Reactor Coolant System cold legs is < 300°F.

APPLICABILITY: ALL MODES.

ACTION:

a. With the flow rate of reactor coolant through the core < 1000 gpm, immediately suspend all operations involving a reduction in boron concentration of the Reactor Coolant System.

b. With more than two charging pumps capable of injecting into the Reactor Coolant System and the temperature of one or more of the Reactor Coolant System cold legs is < 300°F, take immediate action to comply with 3.1.1.3.b.

SURVEILLANCE REQUIREMENTS

4.1.1.3.1* The reactor coolant flow rate through the core shall be determined to be ≥ 1000 gpm prior to the start of and at least once per hour during a reduction in the Reactor Coolant System boron concentration by either:

a. Verifying at least one reactor coolant pump is in operation, or

b. Verifying that at least one low pressure safety injection pump is in operation and supplying ≥ 1000 gpm through the core.

4.1.1.3.2 One charging pump shall be demonstrated not capable of injecting into the Reactor Coolant System at least once per 12 hours whenever the temperature of one or more of the Reactor Coolant System cold legs is < 300°F.

* When the plant is in MODE 1 or 2, reactor coolant pumps are required to be in operation. Therefore, Surveillance Requirement 4.1.1.3.1 does not have to be performed in MODES 1 and 2.

MODERATOR TEMPERATURE COEFFICIENT (MTC)

LIMITING CONDITION FOR OPERATION (Continued)

3.1.1.4 The moderator temperature coefficient (MTC) shall be within the limits specified in the CORE OPERATING LIMITS REPORT. The upper limit shall be less than or equal to:

a. 0.7×10^{-4} $\Delta K/K/{}^{\circ}F$ whenever THERMAL POWER is ≤ 70% of RATED THERMAL POWER,

b. 0.4×10^{-4} $\Delta K/K/{}^{\circ}F$ whenever THERMAL POWER IS > 70% of RATED THERMAL POWER.

APPLICABILITY: MODES 1 and 2*#

ACTION:

With the moderator temperature coefficient outside any one of the above limits, be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENT

4.1.1.4.1 The MTC shall be determined to be within its limits by confirmatory measurements. MTC measured values shall be extrapolated and/or compensated to permit direct comparision with the predicted values.

*With $K_{eff} \geq 1.0$.

#See Special Test Exemption 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

4.1.1.4.2 The MTC shall be determined at the following frequencies and THERMAL POWER conditions during each fuel cycle:

a. Prior to initial operation above 5% of RATED THERMAL POWER, after each refueling.

b. At any THERMAL POWER, within 14 EFPD after each fuel loading at equilibrium boron concentration.

REACTIVITY CONTROL SYSTEMS

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.5 The Reactor Coolant System temperature (T_{avg}) shall be $\geq$ 515°F when the reactor is critical.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With the Reactor Coolant System temperature (T_{avg}) < 515°F, restore T_{avg} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.5 The Reactor Coolant System temperature (T_{avg}) shall be determined to be $\geq$ 515°F.

a. Within 15 minutes prior to making the reactor critical, and

b. At least once per hour when the reactor is critical and the Reactor Coolant System temperature (T_{avg}) is < 525°F.

#With $K_{eff} \geq 1.0$.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

CEA POSITION

LIMITING CONDITION FOR OPERATION

3.1.3.1 All CEAs shall be OPERABLE with each CEA of a given group positioned within 10 steps (indicated position) of all other CEAs in its group, and the CEA Motion Inhibit and the CEA Deviation Circuit shall be OPERABLE.

APPLICABILITY: MODES 1[1] and 2[1].

ACTION:

INOPERABLE EQUIPMENT	REQUIRED ACTION
A. One or more CEAs trippable and misaligned from all other CEAs in its group by > 10 steps and < 20 steps. OR One CEA trippable and misaligned from all other CEAs in its group by ≥ 20 steps.	A.1 Reduce THERMAL POWER to < 70% of the maximum allowable THERMAL POWER within 1 hour and restore CEA(s) misalignment within 2 hours or otherwise be in MODE 3 within the next 6 hours.
B. CEA Motion Inhibit inoperable.	B.1 Verify the indicated position of each CEA to be within 10 steps of all other CEAs in its group within 1 hour and every 4 hours thereafter, and restore CEA Motion Inhibit to OPERABLE status within 6 hours or otherwise be in MODE 3 within the next 6 hours. OR B.2[2] Place and maintain the CEA drive system mode switch in either the "off" or "manual" position, and withdraw all CEAs in group 7 to ≥ 172 steps within 6 hours or otherwise be in MODE 3 within the next 6 hours.

(1) See Special Test Exception 3.10.2

(2) Performance of Action B.2 is allowed only when not in conflict with either Required Action A.1 or C.1.

ACTION (Continued):

C. CEA Deviation Circuit inoperable.	C.1 Verify the indicated position of each CEA to be within 10 steps of all other CEAs in its group within 1 hour and every 4 hours thereafter or otherwise be in MODE 3 within the next 6 hours.
D. One or more CEAs untrippable. OR Two or more CEAs misaligned by $\geq$ 20 steps.	D.1 Be in MODE 3 within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 Verify the indicated position of each CEA to be within 10 steps of all other CEAs in its group at least once per 12 hours AND within 1 hour following any CEA movement larger than 10 steps.

4.1.3.1.2 Verify CEA freedom of movement (trippability) by moving each individual CEA that is not fully inserted into the reactor core 10 steps in either direction at least once per 92 days.

4.1.3.1.3 Verify the CEA Deviation Circuit is OPERABLE at least once per 92 days by a functional test of the CEA group Deviation Circuit which verifies that the circuit prevents any CEA from being misaligned from all other CEAs in its group by more than 10 steps (indicated position).

4.1.3.1.4 Verify the CEA Motion Inhibit is OPERABLE by a functional test which verifies that the circuit maintains the CEA group overlap and sequencing requirements of Specification 3.1.3.6 and that the circuit prevents regulating CEAs from being inserted beyond the Transient Insertion Limits specified in the CORE OPERATING LIMITS REPORT:

a. Prior to each entry into MODE 2 from MODE 3, except that such verification need not be performed more often than once per 31 days, and

b. At least once per 6 months.

"This page intentionally left blank."

This page intentionally left blank.

LIMITING CONDITION FOR OPERATION

3.1.3.3 All shutdown and regulating CEA reed switch position indicator channels and CEA pulse counting position indicator channels shall be OPERABLE and capable of determining the absolute CEA positions within ± 3 steps.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. Deleted.

b. With a maximum of one reed switch position indicator channel per group or one (except as permitted by ACTION item d. below) pulse counting position indicator channel per group inoperable and the CEA(s) with the inoperable position indicator channel partially inserted, within 4 hours either:

   1. Restore the inoperable position indicator channel to OPERABLE status, or

   2. Be in HOT STANDBY, or

   3. Reduce THERMAL POWER to ≤ 70% of the maximum allowable THERMAL POWER level; if negative reactivity insertion is required to reduce THERMAL POWER, boration shall be used. Operation at or below this reduced THERMAL POWER level may continue provided that within the next 4 hours either:

      a) The CEA group(s) with the inoperable position indicator is fully withdrawn while maintaining the withdrawal sequence required by Specification 3.1.3.6 and when this CEA group reaches its fully withdrawn position, the "Full Out" limit of the CEA with the inoperable position indicator is actuated and verifies this CEA to be fully withdrawn. Subsequent to fully withdrawing this CEA group(s), the THERMAL POWER level may be returned to a level consistent with all other applicable specifications; or

LIMITING CONDITION FOR OPERATION (Continued)

b) The CEA group(s) with the inoperable indicator is fully inserted, and subsequently maintained fully inserted, while maintaining the withdrawal sequence and THERMAL POWER level required by Specification 3.1.3.6 and when this CEA group reaches its fully inserted position, the "Full In" limit of the CEA with the inoperable position indicator is actuated and verifies this CEA to be fully inserted. Subsequent operation shall be within the limits of Specification 3.1.3.6.

4. If the failure of the position indicator channel(s) is during STARTUP, the CEA group(s) with the inoperable position indicator channel must be moved to the "Full Out" position and verified to be fully withdrawn via a "Full Out" indicator within 4 hours.

c. With a maximum of one reed switch position indicator channel per group or one pulse counting position indicator channel per group inoperable and the CEA(s) with the inoperable position indicator channel at either its fully inserted position or fully withdrawn position, operation may continue provided:

1. The position of this CEA is verified immediately and at least once per 12 hours thereafter by its "Full In" or "Full Out" limit (as applicable).

2. The fully inserted CEA group(s) containing the inoperable position channel is subsequently maintained fully inserted, and

3. Subsequent operation is within the limits of Specification 3.1.3.6.

d. With one or more pulse counting position indicator channels inoperable, operation in MODES 1 and 2 may continue for up to 24 hours provided all of the reed switch position indicator channels are OPERABLE.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each position indicator channel shall be determined to be OPERABLE by verifying the pulse counting position indicator channels and the reed switch position indicator channels agree within 6 steps at least once per 12 hours.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual CEA drop time, from a fully withdrawn position, shall be $\leq$ 2.75 seconds from when electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90 percent insertion position with:

a. $T_{avg} \geq 515°F$, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

With the drop time of any CEA determined to exceed the above limit, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time shall be demonstrated through measurement with $T_{avg} \geq 515°F$, and all reactor coolant pumps operating prior to reactor criticality:

a. For all CEAs following each removal of the reactor vessel head,

b. For specifically affected individual CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months.

SHUTDOWN CEA INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown CEAs shall be withdrawn to ≥ 176 steps.

APPLICABILITY: MODE 1[1]
MODE 2[1],[2] with any regulating CEA not fully inserted.

ACTION:

INOPERABLE EQUIPMENT	REQUIRED ACTION
A. One or more shutdown CEAs not within limit.	A.1 Restore shutdown CEA(s) to within limit within 2 hours or otherwise be in MODE 3 within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Verify each shutdown CEA is withdrawan ≥ 176 steps at least once per 12 hours.

[1] This LCO is not applicable while performing Specification 4.1.3.1.2.

[2] See Special Test Exceptions 3.10.1 and 3.10.2.

REACTIVITY CONTROL SYSTEMS

REGULATING CEA INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The power dependent insertion limit (PDIL) alarm circuit shall be OPERABLE, and the regulating CEA groups shall be limited to the withdrawal sequence and to the insertion limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY[1]: MODES 1[2] and 2[2],[3].

ACTION:

INOPERABLE EQUIPMENT	REQUIRED ACTION
A. Regulating CEA groups inserted beyond the Transient Insertion Limits provided in the CORE OPERATING LIMITS REPORT.	A.1 Restore regulating CEA groups to within limits specified in the CORE OPERATING LIMITS REPORT within 2 hours or otherwise be in MODE 3 within the next 6 hours. OR A.2 Reduce THERMAL POWER to less than or equal to the fraction of RATED THERMAL POWER allowed by the CEA group position and insertion limits specified in the CORE OPERATING LIMITS REPORT within 2 hours or otherwise be in MODE 3 within the next 6 hours.

[1] This LCO is not applicable while performing Specification 4.1.3.1.2.
[2] See Special Test Exceptions 3.10.1 and 3.10.2.

[3] With $K_{eff} \geq 1.0$

REGULATING CEA INSERTION LIMITS (Continued)

B. Regulating CEA groups inserted between the Long Term Steady State Insertion limit and the Transient Insertion Limit specified in the CORE OPERATING LIMITS REPORT for intervals > 4 hours per 24 hour interval.	B.1 Verify Short Term Steady State Insertion Limits as specified in the CORE OPERATING LIMITS REPORT are not exceeded within 15 minutes or otherwise be in MODE 3 within the next 6 hours. OR B.2 Restrict increases in THERMAL POWER to < 5% RATED THERMAL POWER per hour within 15 minutes or otherwise be in MODE 3 within the next 6 hours.
C. Regulating CEA groups inserted between the Long Term Steady State Insertion Limit and the Transient Insertion Limit specified in the CORE OPERATING LIMITS REPORT for intervals > 5 effective full power days (EFPD) per 30 EFPD or interval > 14 EFPD per 365 EFPD.	C.1 Restore regulating CEA groups to within the Long Term Steady State Insertion Limit specified in the CORE OPERATING LIMITS REPORT within 2 hours or otherwise be in MODE 3 within the next 6 hours.
D. PDIL alarm circuit inoperable.	D.1 Perform Specification 4.1.3.6.1 within 1 hour and once per 4 hours thereafter or otherwise be in MODE 3 within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6.1 Verify each regulating CEA group position is within the Transient Insertion Limits specified in the CORE OPERATING LIMITS REPORT at least once per 12 hours. The provisions of Specification 4.0.4 are not applicable for entering into MODE 2 from MODE 3.

4.1.3.6.2 Verify the accumulated times during which the regulating CEA groups are inserted beyond the Steady State Insertion Limits but within the Transient Insertion Limits specified in the CORE OPERATING LIMITS REPORT at least once per 24 hours.

4.1.3.6.3 Verify PDIL alarm circuit is OPERABLE at least once per 31 days.

THIS PAGE LEFT BLANK INTENTIONALLY

CONTROL ROD DRIVE MECHANISMS

LIMITING CONDITION FOR OPERATION

3.1.3.7 The control rod drive mechanisms shall be de-energized.

APPLICABILITY: MODES 3*, 4, 5 and 6, whenever the RCS boron concentration is less than refueling concentration of Specification 3.9.1.

ACTION:

With any of the control rod drive mechanisms energized, restore the mechanisms to their de-energized state within 2 hours or immediately open the reactor trip circuit breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.7 The control rod drive mechanisms shall be verified to be de-energized at least once per 24 hours.

* The control rod drive mechanisms may be energized for MODE 3 as long as 4 reactor coolant pumps are OPERATING, the reactor coolant system temperature is greater than 500°F, the pressurizer pressure is greater than 2000 psia and the high power trip is operable.

LINEAR HEAT RATE

LIMITING CONDITION FOR OPERATION (Continued)

3.2.1 The linear heat rate, including heat generated in the fuel, clad and moderator, shall not exceed the limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: MODE 1.

ACTION:

During operation with the linear heat rate being monitored by the Incore Detector Monitoring System, comply with the following ACTION:

With the linear heat rate exceeding the limit as indicated by four or more coincident incore channels, within 15 minutes initiate corrective action to reduce the linear heat rate to less than or equal to the limit and either:

a. Restore the linear heat rate to less than or equal to the limit within one hour, or

b. Be in at least HOT STANDBY within the next 6 hours.

During operation with the linear heat rate being monitored by the Excore Detector Monitoring System, comply with the following ACTIONS:

With the linear heat rate exceeding its limit, as indicated by the AXIAL SHAPE INDEX being outside of the power dependent limits on the Power Ratio Recorder, either:

a. Restore the AXIAL SHAPE INDEX to within the limits specified in the CORE OPERATING LIMITS REPORT within 1 hour from initially exceeding the linear heat rate limit, or

b. Be in at least HOT STANDBY within the next 4 hours.

SURVEILLANCE REQUIREMENT

4.2.1.1 The linear heat rate shall be determined to be within its limits by continuously monitoring the core power distribution with either the excore detector monitoring system or with the incore detector monitoring system.

4.2.1.2 Excore Detector Monitoring System[1] - The excore detector monitoring system may be used for monitoring the core power distribution by:

a. Verifying at least once per 12 hours that the CEAs are withdrawn to and maintained at or beyond the Long Term Steady State Insertion Limits of Specification 3.1.3.6.

b. Verifying at least once per 31 days that the AXIAL SHAPE INDEX alarm setpoints are adjusted to within the allowable limits specified in the CORE OPERATING LIMITS REPORT.

4.2.1.3 Incore Detector Monitoring System[2],[3] - The incore detector monitoring system may be used for monitoring the core power distribution by verifying that the incore detector Local Power Density alarms:

a. Are adjusted to satisfy the requirements of the core power distribution map which shall be updated at least once per 31 days.

b. Have their alarm setpoint adjusted to less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT.

---

[1] Only required to be met when the Excore Detector Monitoring System is being used to determine Linear Heat Rate.

[2] Only required to be met when the Incore Detector Monitoring System is being used to determine Linear Heat Rate.

[3] Not required to be performed below 20% RATED THERMAL POWER.

FIGURE 3.2-1 LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR - F^T_r

LIMITING CONDITION FOR OPERATION

3.2.3 The calculated value of F^T_r shall be within the 100% power limit specified in the CORE OPERATING LIMITS REPORT. The F^T_r value shall include the effect of AZIMUTHAL POWER TILT.

APPLICABILITY: MODE 1 with THERMAL POWER >20% RTP*.

ACTION:

With F^T_r exceeding the 100% power limit within 6 hours either:

a. Reduce THERMAL POWER to bring the combination of THERMAL POWER and F^T_r to within the power dependent limit specified in the CORE OPERATING LIMITS REPORT and withdraw the CEAs to or beyond the Long Term Steady State Insertion Limits of Specification 3.1.3.6; or
b. Be in at least HOT STANDBY.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 F^T_r shall be determined to be within the 100% power limit at the following intervals:

a. Prior to operation above 70 percent of RATED THERMAL POWER after each fuel loading,
b. At least once per 31 days of accumulated operation in Mode 1, and
c. Within four hours if the AZIMUTHAL POWER TILT (T_q) is > 0.020.

4.2.3.3 F^T_r shall be determined by using the incore detectors to obtain a power distribution map with all CEAs at or above the Long Term Steady State Insertion Limit for the existing Reactor Coolant Pump Combination.

*See Special Test Exception 3.10.2

AZIMUTHAL POWER TILT - T_q

LIMITING CONDITION FOR OPERATION

3.2.4 The AZIMUTHAL POWER TILT (T_q) shall be $\leq$ 0.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% of RATED THERMAL POWER[1].

ACTION:

a. With the indicated T_q > 0.02 but $\leq$ 0.10, either restore T_q to $\leq$ 0.02 within 2 hours or verify the TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR (F^T_r) is within the limit of Specification 3.2.3 within 2 hours and once per 8 hours thereafter. Or otherwise, reduce THERMAL POWER to $\leq$ 50% of RATED THERMAL POWER within the next 4 hours.

b. With the indicated T_q > 0.10, perform the following actions:[2]
   1. Verify the TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR (F^T_r) is within the limit of Specification 3.2.3 within 2 hours; and
   2. Reduce THERMAL POWER to $\leq$ 50% of RATED THERMAL POWER within 2 hours; and
   3. Restore T_q $\leq$ 0.02 prior to increasing THERMAL POWER. Correct the cause of the out of limit condition prior to increasing THERMAL POWER. Subsequent power operation above 50% of RATED THERMAL POWER may proceed provided that the measured T_q is verified $\leq$ 0.02 at least once per hour for 12 hours, or until verified at 95% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.4.1 Verify T_q is within limit at least once every 12 hours. The provisions of Specification 4.0.4 are not applicable for entering into MODE 1 with THERMAL POWER > 50% of RATED THERMAL POWER from MODE 1.

---

[1] See Special Test Exception 3.10.2.

[2] All subsequent Required Actions must be completed if power reduction commences prior to restoring T_q $\leq$ 0.10.

"This page intentionally left blank."

This page intentionally left blank.

DNB MARGIN

LIMITING CONDITION FOR OPERATION

3.2.6 The DNB margin shall be preserved by maintaining the cold leg temperature, pressurizer pressure, reactor coolant flow rate, and AXIAL SHAPE INDEX within the limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its specified limits, restore the parameter to within its above specified limits within 2 hours or reduce THERMAL POWER to ≤ 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.6.1 The cold leg temperature, pressurizer pressure, and AXIAL SHAPE INDEX shall be determined to be within the limits specified in the CORE OPERATING LIMITS REPORT at least once per 12 hours. The reactor coolant flow rate shall be determined to be within the limit specified in the CORE OPERATING LIMITS REPORT at least once per 31 days.

4.2.6.2 The provisions of Specification 4.0.4 are not applicable.

THIS PAGE LEFT BLANK INTENTIONALLY

THIS PAGE LEFT BLANK INTENTIONALLY

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTIVE INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1.1 As a minimum, the reactor protective instrumentation channels and bypasses of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each reactor protective instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-1.

4.3.1.1.2 The logic for the bypasses shall be demonstrated OPERABLE during the at power CHANNEL FUNCTIONAL TEST of channels affected by bypass operation. The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

4.3.1.1.3 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be demonstrated to be within its limit at least once per 18 months. Neutron detectors are exempt from response time testing. Each test shall include at least one channel per function 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 function as shown in the "Total No. of Channels" column of Table 3.3-1.

TABLE 3.3-1

REACTOR PROTECTIVE INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2 and *	1
2. Power Level - High	4	2(f)	3	1, 2, 3(d)	2
3. Reactor Coolant Flow - Low	4	2(a)	3	1, 2	2
4. Pressurizer Pressure - High	4	2	3	1, 2	2
5. Containment Pressure - High	4	2	3	1, 2	2
6. Steam Generator Pressure - Low	4	2(b)	3	1, 2	2
7. Steam Generator Water Level - Low	4	2	3	1, 2	2
8. Local Power Density - High	4	2(c)	3	1	2
9. Thermal Margin/Low Pressure	4	2(a)	3	1,2	2
10. Loss of Turbine - Hyraulic Fluid Pressure - Low	4	2(c)	3	1	2

TABLE 3.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11. Wide Range Logarithmic Neutron Flux Monitor - Shutdown	4	0	2	3, 4, 5	4
12. DELETED					
13. Reactor Protection System Logic Matrices	6	1	6	1, 2 and *	5
14. Reactor Protection System Logic Matrix Relays	4/Matrix	3/Matrix	4/Matrix	1, 2 and *	6
15. Reactor Trip Breakers	4	3	4	1, 2 and *	6

TABLE NOTATION

*With the protective system trip breakers in the closed position and the CEA drive system capable of CEA withdrawal.

(a) Trip may be bypassed below 5% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is ≥ 5% of RATED THERMAL POWER.

(b) Trip may be manually bypassed when steam generator pressure is < 800 psia and all CEAs are fully inserted; bypass shall be automatically removed when steam generator pressure is ≥ 800 psia.

(c) Trip may be bypassed below 15% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is ≥ 15% of RATED THERMAL POWER.

(d) Trip does not need to be operable if all the control rod drive mechanisms are de-energized or if the RCS boron concentration is greater than or equal to the refueling concentration of Specification 3.9.1.

(e) DELETED

(f) ΔT Power input to trip may be bypassed below 5% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is ≥ 5% of RATED THERMAL POWER.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 4 hours and/or open the protective system trip breakers.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may continue provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. The inoperable channel shall either be restored to OPERABLE status, or placed in the tripped condition, within 48 hours.

b. Within 1 hour, all functional units receiving an input from the inoperable channel are also declared inoperable, and the appropriate actions are taken for the affected functional units.

c. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be removed from service for up to 48 hours, provided one of the inoperable channels is placed in the tripped condition.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS

ACTION 3 - NOT USED

ACTION 4 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, immediately verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, and at least once per 4 hours thereafter.

ACTION 5 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours.

ACTION 6 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours.

TABLE 4.3-1

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	S/U(1)	N.A.
2. Power Level - High				
a. Nuclear Power	S	D(2), M(3),Q(5)	M	1, 2, 3*
b. ΔT Power	S	D(4), Q	M	1
3. Reactor Coolant Flow - Low	S	R	M	1, 2
4. Pressurizer Pressure - High	S	R	M	1, 2
5. Containment Pressure - High	S	R	M	1, 2
6. Steam Generator Pressure - Low	S	R	M	1, 2
7. Steam Generator Water Level - Low	S	R	M	1, 2
8. Local Power Density - High	S	R	M	1
9. Thermal Margin/Low Pressure	S	R	M	1, 2
10. Loss of Turbine--Hydraulic Fluid Pressure - Low	N.A.	R	S/U(1)	N.A.

TABLE 4.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
11. Wide Range Logarithmic Neutron Flux Monitor - Shutdown	S	R(5)	S/U(1)	3, 4, 5
12. DELETED				
13. Reactor Protection System Logic Matrices	N.A.	N.A.	M and S/U (1)	1, 2 and *
14. Reactor Protection System Logic Matrix Relays	N.A.	N.A.	M and S/U (1)	1, 2 and *
15. Reactor Trip Breakers	N.A.	N.A.	M	1, 2 and *

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With reactor trip breaker closed.

(1) - If not performed in previous 7 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER; adjust "Nuclear Power Calibrate" potentiometers to make nuclear power signals agree with calorimetric calculation. During PHYSICS TESTS, these daily calibrations of nuclear power and ΔT power may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(3) - Above 15% of RATED THERMAL POWER, recalibrate the excore detectors which monitor the AXIAL SHAPE INDEX by using the incore detectors or restrict THERMAL POWER during subsequent operations to $\leq$ 90% of the maximum allowed THERMAL POWER level with the existing Reactor Coolant Pump combination.

(4) - Above 15% of RATED THERMAL POWER, adjust "ΔT Pwr Calibrate" potentiometers to null "Nuclear Pwr - ΔT Pwr". During PHYSICS TESTS, these daily calibrations of nuclear power and ΔT power may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(5) Neutron detectors are excluded from the CHANNEL CALIBRATION.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2.1 The engineered safety feature actuation system instrumentation channels and bypasses shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an engineered safety feature actuation system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, either adjust the trip setpoint to be consistent with the value specified in the Trip Setpoint column of Table 3.3-4 within 2 hours or declare the channel inoperable and take the ACTION shown in Table 3.3-3.

b. With an engineered safety feature actuation system instrumentation channel inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each engineered safety feature acutation system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the bypasses shall be demonstrated OPERABLE during the at power CHANNEL FUNCTIONAL TEST of channels affects by bypass operation. The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

SURVEILLANCE REQUIREMENTS (Continued)

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESF function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per function 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 ESF function as shown in the "Total No. of Channels" Column of Table 3.3-3.

ENGINEERED SAFETY FEATURE AC[illegible]ATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION (SIAS)(d)					
a. Manual (Trip Buttons)	2	1	2	1, 2, 3, 4	1
b. Containment Pressure - High	4	2	3	1, 2, 3	2
c. Pressurizer Pressure - Low	4	2	3	1, 2, 3(a)	2
d. Automatic Actuation Logic	2	1	2	1, 2, 3	5
2. CONTAINMENT SPRAY (CSAS)					
a. Manual (Trip Buttons)	2	1	2	1, 2, 3, 4	1
b. Containment Pressure-- High - High	4	2(b)	3	1, 2, 3	2
c. Automatic Actuation Logic	2	1	2	1, 2, 3	5
3. CONTAINMENT ISOLATION (CIAS)					
a. Manual CIAS (Trip Buttons)	2	1	2	1, 2, 3, 4	1
b. Manual SIAS (Trip Buttons)	2	1	2	1, 2, 3, 4	1
c. Containment Pressure - High	4	2	3	1, 2, 3	2
d. Pressurizer Pressure - Low	4	2	3	1, 2, 3(a)	2
e. Automatic Actuation Logic	2	1	2	1, 2, 3	5

TABLE 3.: Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. MAIN STEAM LINE ISOLATION					
a. Manual MSI (Trip Buttons) High	2	1	2	1, 2, 3, 4	1
b. Containment Pressure-High	4	2	3	1, 2, 3	2
c. Steam Generator Pressure - Low	4	2	3	1, 2, 3(c)	2
d. Automatic Actuation Logic	2/Steam Generator	1/Steam Generator	2/Steam Generator	1, 2, 3	5
5. ENCLOSURE BUILDING FILTRATION (EBFAS)					
a. Manual EBFAS (Trip Buttons)	2	1	2	1, 2, 3, 4	1
b. Manual SIAS (Trip Buttons)	2	1	2	1, 2, 3, 4	1
c. Containment Pressure-High	4	2	3	1, 2, 3	2
d. Pressurizer Pressure-Low	4	2	3	1, 2, 3(a)	2
e. Automatic Actuation Logic	2	1	2	1, 2, 3	5
6. CONTAINMENT SUMP RECIRCULATION (SRAS)					
a. Manual SRAS (Trip Buttons)	2	1	2	1, 2, 3, 4	1
b. Refueling Water Storage Tank - Low	4	2	3	1, 2, 3	4
c. Automatic Actuation Logic	2	1	2	1, 2, 3	5

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. DELETED					
8. LOSS OF POWER					
a. 4.16 kv Emergency Bus Undervoltage - level one	4/bus	2/Bus	3/bus	1, 2, 3	2
b. 4.16 kv Emergency Bus Undervoltage - level two	4/Bus	2/Bus	3/Bus	1, 2, 3	2

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
9. AUXILIARY FEEDWATER					
a. Manual	1/pump	1/pump	1/pump	1, 2, 3	6
b. Steam Generator Level - Low	4	2	3	1, 2, 3	2
c. Automatic Actuation Logic	2/Steam Generator	1/Steam Generator	2/Steam Generator	1, 2, 3	5
10. STEAM GENERATOR BLOWDOWN					
a. Steam Generator Level - Low	4	2	3	1, 2, 3	2

TABLE 3.3-3 (Continued)

TABLE NOTATION

(a) Trip function may be bypassed when pressurizer pressure is < 1850 psia; bypass shall be automatically removed when pressurizer pressure is ≥ 1850 psia.

(b) An SIAS signal is first necessary to enable CSAS logic.

(c) Trip function may be bypassed when steam generator pressure is < 700 psia; bypass shall be automatically removed when steam generator pressure is ≥ 700 psia.

(d) In MODE 4 the HPSI pumps are not required to start automatically on a SIAS.

(e) DELETED

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in COLD SHUTDOWN within the next 36 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may continue provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. The inoperable channel shall either be restored to OPERABLE status, or placed in the tripped condition, within 48 hours.

b. Within 1 hour, all functional units receiving an input from the inoperable channel are also declared inoperable, and the appropriate actions are taken for the affected functional units.

c. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be removed from service for up to 48 hours, provided one of the inoperable channels is placed in the tripped condition.

TABLE 3.3-3 (Continued)

ACTION 3 - DELETED

ACTION 4 - With the number of OPERABLE channels one less than the Total Number of Channels and with the pressurizer pressure:

a. < 1850 psia: immediately place the inoperable channel in the bypassed condition; restore the inoperable channel to OPERABLE status prior to increasing the pressurizer pressure above 1850 psia.

b. $\geq$ 1850 psia, operation may continue with the inoperable channel in the bypassed condition, provided the following condition is satisfied:

1. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be removed from service for up to 2 hours for surveillance testing per Specification 4.3.2.1.1 provided BOTH of the inoperable channels are placed in the bypassed condition.

ACTION 5 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT SHUTDOWN within the next 12 hours.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 4.42 psig	≤ 5.07 psig
c. Pressurizer Pressure - Low	≥ 1714 psia	≥ 1704 psia
d. Automatic Actuation Logic	Not Applicable	Not Applicable
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	≤ 9.48 psig	≤ 10.11 psig
c. Automatic Actuation Logic	Not Applicable	Not Applicable
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Containment Pressure - High	≤ 4.42 psig	≤ 5.07 psig
d. Pressurizer Pressure - Low	≥ 1714 psia.	≥ 1704 psia
e. Automatic Actuation Logic	Not Applicable	Not Applicable
4. MAIN STEAM LINE ISOLATION		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 4.42 psig	≤ 5.07 psig
c. Steam Generator Pressure - Low	≥ 572 psia	≥ 558 psia
d. Automatic Actuation Logic	Not Applicable	Not Applicable

[illegible] (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
5. ENCLOSURE BUILDING FILTRATION (EBFAS)		
a. Manual EBFAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Containment Pressure - High	≤ 4.42 psig	≤ 5.07 psig
d. Pressurizer Pressure - Low	≥ 1714 psia	≥ 1704 psia
e. Automatic Actuation Logic	Not Applicable	Not Applicable
6. CONTAINMENT SUMP RECIRCULATION (SRAS)		
a. Manual SRAS (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Storage Tank -Low	46 ± 3 inches above tank bottom	46 ± 6 inches above tank bottom
c. Automatic Actuation Logic	Not Applicable	Not Applicable
7. DELETED		

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage - level one	≥ 2912 volts with a 2.0 ± 0.1 second time delay	≥ 2877 volts with a 2.0 ± 0.1 second time delay
b. 4.16 kv Emergency Bus Undervoltage - level two	≥ 3700 volts with an 8.0 ± 2.0 second time delay	≥ 3663 volts with an 8.0 ± 2.0 second time delay
9. AUXILIARY FEEDWATER		
a. Manual	Not Applicable	Not Applicable
b. Steam Generator Level - Low	≥ 26.8%	≥ 25.2%
c. Automatic Actuation Logic	Not Applicable	Not Applicable
10. STEAM GENERATOR BLOWDOWN		
a. Steam Generator Level - Low	≥ 26.8%	≥ 25.2%

E 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N. A.
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Pressurizer Pressure - Low	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Containment Pressure-- High - High	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
3. CONTAINMENT ISOLATION (CIAS)				
a. Manual CIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
c. Containment Pressure - High	S	R	M	1, 2, 3
d. Pressurizer Pressure - Low	S	R	M	1, 2, 3
e. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
4. MAIN STEAM LINE ISOLATION				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Steam Generator Pressure - Low	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
5. ENCLOSURE BUILDING FILTRATION (EBFAS)				
a. Manual EBFAS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
c. Containment Pressure - High	S	R	M	1, 2, 3
d. Pressurizer Pressure - Low	S	R	M	1, 2, 3
e. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3

TABLE . (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
6. CONTAINMENT SUMP RECIRCULATION (SRAS)				
a. Manual SRAS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
7. DELETED				
8. LOSS OF POWER				
a. 4.16 kv Emergency Bus Undervoltage - level one	S	R	M	1, 2, 3
b. 4.16 kv Emergency Bus Undervoltage - level two	S	R	M	1, 2, 3
9. AUXILIARY FEEDWATER				
a. Manual	N.A.	N.A.	R	N.A.
b. Steam Generator Level - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M	1, 2, 3
10. STEAM GENERATOR BLOWDOWN				
a. Steam Generator Level - Low	S	R	M	1, 2, 3

TABLE 4.3-2 (Continued)

TABLE NOTATION

(1) The coincident logic circuits shall be tested automatically or manually at least once per 31 days. The automatic test feature shall be verified OPERABLE at least once per 31 days. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or other specified conditions for surveillance testing of the following:

a. Pressurizer Pressure Safety Injection Automatic Actuation Logic; and

b. Pressurizer Pressure Containment Isolation Automatic Actuation Logic; and

c. Steam Generator Pressure Main Steam Line Isolation Automatic Actuation Logic; and

d. Pressurizer Pressure Enclosure Building Filtration Automatic Actuation Logic.

Testing of the automatic actuation logic for Pressurizer Pressure Safety Injection, Pressurizer Pressure Containment Isolation, and Pressurizer Pressure Enclosure Building Filtration shall be performed within 12 hours after exceeding a pressurizer pressure of 1850 psia in MODE 3. Testing of the automatic actuation logic for Steam Generator Pressure Main Steam Line Isolation shall be performed within 12 hours after exceeding a steam generator pressure of 700 psia in MODE 3.

INSTRUMENTATION

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SENSOR CABINET POWER SUPPLY DRAWERS

LIMITING CONDITION FOR OPERATION

3.3.2.2 The engineered safety feature actuation system Sensor Cabinets (RC02A1, RC02B2, RC02C3 & RC02D4) Power Supply Drawers shall be OPERABLE and energized from the normal power source with the backup power source available. The normal and backup power sources for each sensor cabinet is detailed in Table 3.3-5a:

CABINET	NORMAL POWER	BACKUP POWER
RC02A1	VA-10	VA-40
RC02B2	VA-20	VA-30
RC02C3	VA-30	VA-20
RC02D4	VA-40	VA-10

Table 3.3-5a

APPLICABILITY: MODES 1, 2, 3 and 4

ACTION:

With any of the Sensor Cabinet Power Supply Drawers inoperable, or either the normal or backup power source not available as delineated in Table 3.3-5a, restore the inoperable Sensor Cabinet Power Supply Drawer to OPERABLE status within 48 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.3.2.2.1 The engineered safety feature actuation system Sensor Cabinet Power Supply Drawers shall be determined OPERABLE once per shift by visual inspection of the power supply drawer indicating lamps.

4.3.2.2.2 Verify the operability of the Sensor Cabinet Power Supply auctioneering circuit at least one per 18 months.

INSTRUMENTATION

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels shown in Table 3.3-6 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel alarm/trip setpoint exceeding the value shown in Table 3.3-6, adjust the setpoint to within the limit within 2 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION shown in Table 3.3-6. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1.1 Each radiation monitoring instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-3.

4.3.3.1.2 DELETED

4.3.3.1.3 Verify the response time of the control room isolation channel at least once per 18 months.

TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION

INSTRUMENT			MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1.	AREA MONITORS						
	a.	Delete					
	b.	Control Room Isolation	2	ALL MODES	2 mR/hr	10^{-1} - 10^{4} mR/hr	16
	c.	Containment High Range	1	1, 2, 3, & 4	100 R/hr	10^{0} - 10^{8} R/hr	17
2.	PROCESS MONITORS						
	a.	Containment Atmosphere-Particulate	1	1, 2, 3, & 4	NA	10 - 10^{+6} cpm	14
	b.	Containment Atmosphere-Gaseous	1	1, 2, 3, & 4	NA	10 - 10^{+6} cpm	14
	c.	Noble Gas Effluent Monitor (high range) (Unit 2 stack)	1	1, 2, 3, & 4	2 x 10^{-1} uci/cc	10^{-3} - 10^{5} uci/cc	17

TABLE NOTATION

(a) DELETED

ACTION 13 - DELETED

ACTION 14 - With the number of process monitors OPERABLE less than required by the MINIMUM CHANNELS OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.6.1.

ACTION 15 - DELETED

ACTION 16 - 1) With the number of OPERABLE channels one less than required by the MINIMUM CHANNELS OPERABLE requirement, restore the inoperable channel to OPERABLE status within 7 days or initiate and maintain operation of the control room emergency ventilation system in the recirculation mode of operation.

2) With the number of OPERABLE channels two less than required by the MINIMUM CHANNELS OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency ventilation system in the recirculation mode of operation.

ACTION 17 - With the number of OPERABLE channels less than required by the MINIMUM CHANNELS OPERABLE requirements, initiate the preplanned alternate method of monitoring the appropriate parameter(s), within 72 hours, and:

1) either restore the inoperable channel(s) to OPERABLE status within 7 days of the discovery or

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

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT			CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1.	AREA MONITORS					
	a.	Deleted				
	b.	Control Room Isolation	S	R	M	ALL MODES
	c.	Containment High Range	S	R*	M	1, 2, 3, & 4
2.	PROCESS MONITORS					
	a.	Containment Atmosphere-Particulate	S	R	M	1, 2, 3, & 4
	b.	Containment Atmosphere-Gaseous	S	R	M	1, 2, 3, & 4
	c.	Noble Gas Effluent Monitor (high range) (Unit 2 Stack)	S	R	M	1, 2, 3, & 4

* Calibration of the sensor with a radioactive source need only be performed on the lowest range. Higher ranges may be calibrated electronically.

INSTRUMENTATION

REMOTE SHUTDOWN INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.5 The remote shutdown monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE with readouts displayed external to the control room.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the number of OPERABLE remote shutdown moitoring instrumentation channels less than required by Table 3.3-9, either:

a. Restore the inoperable channel to OPERABLE status within 7 days, or

b. Be in HOT SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.5 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Wide Range Logarithmic Neutron Flux Monitor	Hot Shutdown Panel (C-21)	10^{-8}% - 100%	1
2. Reactor Trip Breaker Indication	Reactor Trip Switchgear (Q03)	OPEN-CLOSE	1/trip breaker
3. Reactor Cold Leg Temperature	Hot Shutdown Panel (C-21)	0-600°F	1
4. Pressurizer Pressure	Hot Shutdown Panel (C-21)		
a. Low Range		0-1600 psia	1
b. High Range		1500-2500 psia	1
5. Pressurizer Level	Hot Shutdown Panel (C-21)	0-100%	1
6. Steam Generator Pressure	Hot Shutdown Panel (C-21)	0-1200 psia	1/steam generator
7. Steam Generator Level	Hot Shutdown Panel (C-21	0-100%	1/steam generator

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Wide Range Logarithmic Neutron Flux	M	R*
2. Reactor Trip Breaker Indication	M	N.A.
3. Reactor Cold Leg Temperature	M	R
4. Pressurizer Pressure		
a. Low Range	M	R
b. High Range	M	R
5. Pressurizer Level	M	R
6. Steam Generator Level	M	R
7. Steam Generator Pressure	M	R

*Neutron detectors are excluded from the CHANNEL CALIBRATION.

INSTALLATION

ACCIDENT MONITORING

LIMITING CONDITION FOR OPERATION

3.3.3.8 The accident monitoring instrumentaiton channels shown in Table 3.3-11 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. Actions per Table 3.3-11.

SURVEILLANCE REQUIREMENTS

4.3.3.8 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-7.

ACCIDENT MONITORING INSTRUMENTATION

Instrument	Total No. of Channels	Minimum Channels Operable	Action
1. Pressurizer Water Level	2	1	1
2. Auxiliary Feedwater Flow Rate	2/S.G.	1/S.G.	1
3. RCS Subcooled/Superheat Monitor	2	1	2
4. PORV Position Indicator Acoustic Monitor	1/valve	1/valve	3
5. PORV Block Valve Position Indicator	1/valve	1/valve	3
6. Safety Valve Position Indicator Acoustic Monitor	1/valve	1/valve	3
7. Containment Pressure (Wide Range)	2	1	4
8. Containment Water Level (Narrow Range)	1	1	7##
9. Containment Water Level (Wide Range)	2	1	4
10. Core Exit Thermocouples	4 CETs/core quadrant	2 CETs in any of 2 core quadrants	5
11. Main Steam Line Radiation Monitor	3	3	6
12. Reactor Vessel Coolant Level	2*	1*	8

* A channel is eight (8) sensors in a probe. A channel is operable if four (4) or more sensors, two (2) or more in the upper four and two (2) or more in the lower four, are operable.

##Refer to ACTION statement in Technical Specification 3.4.6.1.

TABLE 3.3-11 (Continued)

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels less than the MINIMUM CHANNELS OPERABLE requirements of Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 30 days or be in HOT STANDBY within the next 12 hours.

ACTION 2 - With the number of channels OPERABLE less than the MINIMUM CHANNELS OPERABLE, determine the subcooling margin once per 12 hours.

ACTION 3 - With any individual valve position indicator inoperable, obtain quench tank temperature, level and pressure information, and monitor discharge pipe temperature once per shift to determine valve position. This action is not required if the PORV block valve is closed with power removed in accordance with Specification 3.4.3.a or 3.4.3.b.

ACTION 4 - a. With the number of OPERABLE accident monitoring instrumentation channels less than the total number of channels shown in Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 7 days, or submit a special report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction, the plans for restoring the channel(s) to OPERABLE status, and any alternate methods in affect for estimating the applicable parameter during the interim.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the MINIMUM CHANNELS OPERABLE requirements of Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 48 hours, or submit a special report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction, the plans for restoring the channel(s) to OPERABLE status, and any alternate methods in affect for estimating the applicable parameter during the interim.

ACTION 5 - With the number of OPERABLE accident monitoring instrumentation channels less than the MINIMUM CHANNELS OPERABLE requirements of Table 3.3-11, restore the inoperable channel(s) to OPERABLE status within 48 hours, or begin at least HOT SHUTDOWN within the next 12 hours.

ACTION 6 - With any channel of radiation monitoring instrumentation inoperable, portable hand-held radiation detection equipment will be used to assess radiation releases from the atmospheric dump valves and steam generator safeties subsequent to a steam generator tube rupture.

ACTION 7 - Restore the inoperable system to OPERABLE status within 7 days or be in COLD SHUTDOWN within the next 36 hours. (See the ACTION statement in Technical Specification 3.4.6.1.).

ACTION 8 - With the number of OPERABLE Channels one less than the MINIMUM CHANNELS OPERABLE in Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 48 hours if repairs are feasible without shutting down or:

1. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 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; and

2. Restore the system to OPERABLE status at the next scheduled refueling; and

3. Initiate an alternate method of monitoring the Reactor Vessel inventory.

TABLE 4.3-7

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT		CHANNEL CHECK	CHANNEL CALIBRATION
1.	Pressurizer Water Level	M	R
2.	Auxiliary Feedwater Flow Rate	M	R
3.	Reactor Coolant System Subcooled/Superheat Monitor	M	R
4.	PORV Position Indicator (Acoustic Monitor)	M	R
5.	PORV Block Valve Position Indicator	N.A.	R
6.	Safety Valve Position Indicator (Acoustic Monitor)	M	R
7.	Containment Pressure	M	R
8.	Containment Water Level (Narrow Range)	M	R
9.	Containment Water Level (Wide Range)	M	R
10.	Core Exit Thermocouples	M	R*
11.	Main Steam Line Radiation Monitor	M	R
12.	Reactor Vessel Coolant Level	M	R*

*Electronic calibration from the ICC cabinets only.

INSTRUMENTATION

CONTAINMENT PURGE VALVE ISOLATION SIGNAL

LIMITING CONDITION FOR OPERATION

3.3.4 One Containment Purge Valve Isolation Signal containment gaseous radiation monitor channel, one Containment Purge Valve Isolation Signal containment particulate radiation monitor channel, and one Containment Purge Valve Isolation Signal automation logic train shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With no OPERABLE containment purge valve isolation signal, containment gaseous radiation monitor channel, containment purge valve isolation signal, containment particulate radiation monitor channel, and containment purge valve isolation signal automatic logic train, enter the applicable conditions and required ACTIONS for the affected valves of Technical Specification 3.6.3.1, "Containment Isolation Valves."

SURVEILLANCE REQUIREMENTS

4.3.4.1 Perform a CHANNEL CHECK on each Containment Purge Valve Isolation Signal containment gaseous and particulate radiation monitor channel at least once per 12 hours.

4.3.4.2 Perform a CHANNEL FUNCTIONAL TEST on each Containment Purge Valve Isolation Signal containment gaseous and particulate radiation monitor channel at least once per 31 days.

This surveillance shall include verification of the trip value in accordance with the following:

The trip value shall be such that the containment purge effluent shall not result in calculated concentrations of radioactivity offsite in excess of 10 CFR Part 20, Appendix B, Table II. For the purposes of calculating this trip value, a $x/Q = 5.8 \times 10^{-6}$ sec/m^3 shall be used when the system is aligned to purge through the building vent and a $x/Q = 7.5 \times 10^{-8}$ sec/m^3 shall be used when the system is aligned to purge through the Unit 1 stack, the gaseous and particulate (Half Lives greater than 8 days) radioactivity shall be assumed to be Xe-133 and Cs-137, respectively. However, the setpoints shall be no greater than 5×10^5 cpm.

4.3.4.3 Perform a CHANNEL FUNCTIONAL TEST on each Containment Purge Valve Isolation Signal automatic actuation logic train at least once per 31 days. This actuation logic shall include verification of the proper operation of the actuation relay.

4.3.4.4 Perform a CHANNEL CALIBRATION on each Containment Purge Valve Isolation Signal containment gaseous and particulate radiation monitor channel at least once per 18 months.

4.3.4.5 Verify Containment Purge Valve Isolation Signal response time at least once per 18 months. Each test shall include at least one containment gaseous and one containment particulate radiation monitor channel such that all channels are tested at least once every N times 18 months where N is the total number of containment gaseous or total number of containment particulate radiation monitor channels.

REACTOR COOLANT SYSTEM

COOLANT LOOPS AND COOLANT CIRCULATION

STARTUP AND POWER OPERATION

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2*.

ACTION:

With the requirements of the above specification not met, be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.1 The above required reactor coolant loops shall be verified to be in operation at least once per 12 hours.

* See Special Test Exception 3.10.4.

REACTOR COOLANT SYSTEM

COOLANT LOOPS AND COOLANT CIRCULATION

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 Two reactor coolant loops shall be OPERABLE and one reactor coolant loop shall be in operation.

> NOTE
>
> All reactor coolant pumps may not be in operation for up to 1 hour per 8 hour period provided:
>
> a. no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration; and
>
> b. core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTION:

a. With one reactor coolant loop inoperable, restore the required reactor coolant loop to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant loop OPERABLE or in operation, immediately suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return one required reactor coolant loop to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 The required reactor coolant pump, if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignment and indicated power available.

4.4.1.2.2 One reactor coolant loop shall be verified to be in operation at least once per 12 hours.

4.4.1.2.3 Each steam generator secondary side water level shall be verified to be $\geq$ 10% narrow range at least once per 12 hours.

COOLANT LOOPS AND COOLANT CIRCULATION

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.3 Two loops or trains consisting of any combination of reactor coolant loops or shutdown cooling trains shall be OPERABLE and one loop or train shall be in operation.

NOTES

1. All reactor coolant pumps and shutdown cooling pumps may not be in operation for up to 1 hour per 8 hour period provided:
   a. no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration; and
   b. core outlet temperature is maintained at least 10°F below saturation temperature.
2. The following restrictions apply when starting the first reactor coolant pump and any RCS cold leg temperature is $\leq$ 275°F. The first reactor coolant pump shall not be started unless:
   a. pressurizer water level is < 43.7%;
   b. pressurizer pressure is < 340 psia; and
   c. secondary water temperature in each steam generator is < 50°F above each RCS cold leg temperature.

APPLICABILITY: MODE 4.

ACTION:

a. With one reactor coolant loop AND two shutdown cooling trains inoperable:

   Immediately initiate action to restore a second reactor coolant loop, or one shutdown cooling train to OPERABLE status.

b. With two reactor coolant loops AND one shutdown cooling train inoperable:

   Immediately initiate action to restore a second shutdown cooling train, or one reactor coolant loop to OPERABLE status, and be in COLD SHUTDOWN within 24 hours.

c. With all reactor coolant loops AND shutdown cooling trains inoperable, OR no reactor coolant loop or shutdown cooling train in operation:

   Immediately suspend all operations involving a reduction in Reactor Coolant System boron concentration and immediately initiate action to restore one reactor coolant loop or one shutdown cooling train to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required pump, if not in operation, shall be determined OPERABLE once per 7 days by verifying correct breaker alignment and indicated power available.

4.4.1.3.2 The required steam generator(s) shall be determined OPERABLE, by verifying the secondary side water level to be $\geq$ 10% narrow range at least once per 12 hours.

4.4.1.3.3 One reactor coolant loop or shutdown cooling train shall be verified to be in operation at least once per 12 hours.

LIMITING CONDITION FOR OPERATION

3.4.1.4 One shutdown cooling train shall be OPERABLE and in operation, and either:

a. One additional shutdown cooling train shall be OPERABLE;

OR

b. The secondary side water level of each steam generator shall be ≥ 10% narrow range.

NOTES

1. The normal or emergency power source may be inoperable in MODE 5.

2. All shutdown cooling pumps may not be in operation for up to 1 hour per 8 hour period provided:
   a. no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration; and
   b. core outlet temperature is maintained at least 10°F below saturation temperature.

3. The following restrictions apply when starting the first reactor coolant pump and any RCS cold leg temperature is ≤ 275°F. The first reactor coolant pump shall not be started unless:
   a. pressurizer water level is < 43.7%;
   b. pressurizer pressure is < 340 psia; and
   c. secondary water temperature in each steam generator is < 50°F above each RCS cold leg temperature.

4. One required shutdown cooling train may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling train is OPERABLE and in operation.

5. All shutdown cooling trains may not be in operation during planned heatup to MODE 4 when at least one reactor coolant loop is in operation.

APPLICABILITY: MODE 5 with Reactor Coolant System loops filled.

ACTION:

a. With one shutdown cooling train inoperable and any steam generator secondary water level not within limits, immediately initiate action to either restore a second shutdown cooling train to OPERABLE status or restore steam generator secondary water levels to within limit.

b. With no shutdown cooling train OPERABLE or in operation, immediately suspend all operations involving a reduction in Reactor Coolant System boron concentration and immediately initiate action to restore one shutdown cooling train to OPERABLE status and operation.

REACTOR COOLANT SYSTEM

COOLANT LOOPS AND COOLANT CIRCULATION

COLD SHUTDOWN - REACTOR COOLANT SYSTEM LOOPS FILLED

SURVEILLANCE REQUIREMENTS

4.4.1.4.1 The required shutdown cooling pump, if not in operation, shall be determined OPERABLE once per 7 days by verifying correct breaker alignment and indicated power available.

4.4.1.4.2 The required steam generators shall be determined OPERABLE, by verifying the secondary side water level to be $\geq$ 10% narrow range at least once per 12 hours.

4.4.1.4.3 One shutdown cooling train shall be verified to be in operation at least once per 12 hours.

COLD SHUTDOWN - REACTOR COOLANT SYSTEM LOOPS NOT FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.5 Two shutdown cooling trains shall be OPERABLE and one shutdown cooling train shall be in operation.

NOTES

1. The normal or emergency power source may be inoperable in MODE 5.

2. All shutdown cooling pumps may not be in operation for up to 15 minutes when switching from one train to another provided:
   a. no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration;
   b. core outlet temperature is maintained at least 10°F below saturation temperature; and
   c. no draining operations to further reduce Reactor Coolant System water volume are permitted.

3. The following restrictions apply when starting the first reactor coolant pump and any RCS cold leg temperature is ≤ 275°F. The first reactor coolant pump shall not be started unless:
   a. pressurizer water level is < 43.7%;
   b. pressurizer pressure is < 340 psia; and
   c. secondary water temperature in each steam generator is < 50°F above each RCS cold leg temperature.

4. One shutdown cooling train may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling train is OPERABLE and in operation.

APPLICABILITY: MODE 5 with Reactor Coolant System loops not filled.

ACTION:

a. With one shutdown cooling train inoperable, immediately initiate action to restore the required shutdown cooling train to OPERABLE status.

b. With no shutdown cooling train OPERABLE or in operation, immediately suspend all operations involving a reduction in Reactor Coolant System boron concentration and immediately initiate action to restore one shutdown cooling train to OPERABLE status and operation.

COOLANT LOOPS AND COOLANT CIRCULATION

COLD SHUTDOWN - REACTOR COOLANT SYSTEM LOOPS NOT FILLED

SURVEILLANCE REQUIREMENTS

4.4.1.5.1 The required shutdown cooling pump, if not in operation, shall be determined OPERABLE once per 7 days by verifying correct breaker alignment and indicated power available.

4.4.1.5.2 One shutdown cooling train shall be verified to be in operation at least once per 12 hours.

REACTOR COOLANT SYSTEM

REACTOR COOLANT PUMPS

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.6 A maximum of two reactor coolant pumps shall be OPERABLE.

APPLICABILITY: MODE 5

ACTION:

With more than two reactor coolant pumps OPERABLE, take immediate action to comply with Specification 3.4.1.6.

SURVEILLANCE REQUIREMENTS

4.4.1.6 Two reactor coolant pumps shall be demonstrated inoperable at least once per 12 hours by verifying that the motor circuit breakers have been disconnected from their electrical power supply circuits.

REACTOR COOLANT SYSTEM

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.4.2 All pressurizer code safety valves shall be OPERABLE with a lift setting* of 2500 PSIA ± 3%.**

APPLICABILITY: MODES 1, 2, 3,
and 4 with all RCS cold leg temperatures > 275°F

ACTION:

With one inoperable pressurizer code safety valve, restore the inoperable valve to OPERABLE status within 15 minutes. If the inoperable valve is not restored to OPERABLE status within 15 minutes, or if two pressurizer code safety valves are inoperable, be in MODE 3 within 6 hours and in MODE 4 with any RCS cold leg temperature ≤ 275°F within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.2 Each pressurizer code safety valve shall be demonstrated OPERABLE with a lift setting of 2500 PSIA ± 1%, in accordance with Specification 4.0.5.

* The lift setting pressure shall correspond to ambient conditions of the valve(s) at nominal operating temperature and pressure.

** The lift setting shall be within ± 1% following pressurizer code safety valve testing.

REACTOR COOLANT SYSTEM

RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.3 Both power operated relief valves (PORVs) and their associated block valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or both PORVs inoperable and capable of being manually cycled, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) with power maintained to the block valve(s)*; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one PORV inoperable and not capable of being manually cycled, within 1 hour either restore the PORV to OPERABLE status or close its associated block valve and remove power from the block valve; restore the PORV to OPERABLE status within the following 72 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With both PORVs inoperable and not capable of being manually cycled, within 1 hour either restore at least one PORV to OPERABLE status or close the associated block valves and remove power from the block valves and be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With one or both block valves inoperable, within 1 hour restore the block valve(s) to OPERABLE status or prevent its associated PORV(s) from opening automatically. Restore at least one block valve to OPERABLE status within the next hour if both block valves are inoperable; restore any remaining inoperable block valve to OPERABLE status within 72 hours; otherwise be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

*The block valve(s) may be stroked, as necessary, during plant cooldown to prevent thermal binding.

SURVEILLANCE REQUIREMENTS

4.4.3.1 In addition to the requirements of Specification 4.0.5, each PORV shall be demonstrated OPERABLE:

a. Once per 31 days by performance of a CHANNEL FUNCTIONAL TEST, excluding valve operation, and

b. Once per 18 months by performance of a CHANNEL CALIBRATION.

c. Once per 18 months the PORVs shall be bench tested at conditions representative of MODES 3 or 4.

4.4.3.2 Each block valve shall be demonstrated OPERABLE once per 92 days by operating the valve through one complete cycle of full travel. This demonstration is not required if a PORV block valve is closed and power removed to meet Specification 3.4.3 b or c.

REACTOR COOLANT SYSTEM

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.4 The pressurizer shall be OPERABLE with:

a. A water volume greater than or equal to 525 cubic feed (35%) but less than or equal to 1050 cubic feet (70%), and

b. At least two groups of pressurizer heaters each having a capacity of at least 130 kW.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With only one group of pressurizer heaters OPERABLE, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.4.1 The pressurizer water volume shall be determined to be within its limits at least once per 12 hours.

4.4.4.2 Verify at least two groups of pressurizer heaters each have a capacity of at least 130 kW at least once per 92 days.

LIMITING CONDITION FOR OPERATION

3.4.5 Each steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one or more steam generators inoperable, restore the inoperable generator(s) to OPERABLE status prior to increasing T_{avg} above 200°F.

SURVEILLANCE REQUIREMENTS

4.4.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following Augmented Inservice Inspection Program.

4.4.5.1 Augmented Inservice Inspection Program
4.4.5.1.1 Steam Generator Sample Selection and Inspection - Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 4.4-5.

4.4.5.1.2 Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 4.4-6. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.4.5.1.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.4.5.1.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

SURVEILLANCE REQUIREMENTS (Continued)

1. All nonplugged tubes that previously had detectable wall penetrations (>20%).

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 4.4.5.1.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 4.4-6) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspection include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (>10%) further wall penetrations to be included in the above percentage calculations.

4.4.5.1.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-6 at 40 month intervals fall into Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.5.1.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-6 during the shutdown subsequent to any of the following conditions:

1. Priamry-to-secondary tubes leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2.

2. A seismic occurrence greater than the Operating Basis Earthquake.

3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

4. A main steam line or feedwater line break.

4.4.5.1.4 Acceptance Criteria

a. As used in this Specification

1. Imperfection means an exception to the dimensions, finish or contour of a tube or sleeve from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube or sleeve wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube or sleeve.

3. Degraded Tube or sleeve means a tube or sleeve containing imperfections ≥ 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall or sleeve thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Plugging Limit means the imperfection depth at or beyond which the tube shall be repaired because it may become unserviceable prior to the next inspection and is equal to 40% of the nominal wall thickness for tubes or sleeves.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.4.5.1.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg or an inspection from the point of entry (hot leg or cold leg side) completely around the U-bend to the opposite tube end.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug or sleeve all tubes exceeding the plugging limit and plug all defecting sleeves) required by Table 4.4-6.

SURVEILLANCE REQUIREMENTS (Continued)

4.4.5.1.5 Reports

a. Following each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission within 15 days.

b. The complete results of the steam generator tube inservice inspection shall be included in the Annual Operating Report for the period in which this inspection was completed. This report shall include:

   1. Number and extent of tubes inspected.

   2. Location and percent of wall-thickness penetration for each indication of an imperfection.

   3. Identification of tubes plugged or sleeved.

c. Results of steam generator tube inspections which fall into Category C-3 shall be reported pursuant to 10 CFR 50.72. In lieu of any report required pursuant to Specification 6.6.1, a Special Report pursuant to Specification 6.9.2 shall be submitted prior to resumption of plant operation and shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence.

This page intentionally left blank.

This page intentionally left blank.

TABLE 4.4-5

MINIMUM NUMBER OF STEAM GENERATORS TO BE INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	Yes
No. of Steam Generators per Unit	Two
First Inservice Inspection	One
Second & Subsequent Inservice Inspections	One[1]

<u>Table Notation</u>:

1. The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

TABLE 4.4-6

STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S tubes per S.G.	C-1	None	N/A	N/A	N/A	N/A
	C-2	Repair defective tubes and inspect additional 25 tubes in this S.G.*	C-1	None	N/A	N/A
			C-2	Repair defective tubes and inspect additional 45 tubes in this S.G.*	C-1	None
					C-2	Repair defective tubes*
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N/A	N/A
	C-3	Inspect all tubes in this S.G., repair defective tubes and inspect 25 tubes in each other S.G.* Prompt notification to NRC pursuant to 10 CFR 50.72	All other S.G.s are C-1	None	N/A	N/A
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N/A	N/A
			Additional S.G. is C-3	Inspect all tubes in each S.G. and repair defective tubes.* Prompt notification to NRC pursuant to 10 CFR 50.72	N/A	N/A

$S = 3 \frac{N}{n} \%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection

* Repair of defective tubes shall be limited to plugging with the exception of those tubes which may be sleeved. Tubes with defective sleeves shall be plugged.

REACTOR COOLANT SYSTEM

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System leakage detection systems shall be OPERABLE:

a. A containment atmosphere particulate radioactivity monitoring system,

b. The containment sump level monitoring system, and

c. A containment atmosphere gaseous radioactivity monitoring system.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one of the above radioactivity monitoring leakage detection systems inoperable, operations may continue for up to 30 days provided:

   1. The other two above required leakage detection systems are OPERABLE, and

   2. Appropriate grab samples are obtained and analyzed at least once per 24 hours:

   otherwise, be in COLD SHUTDOWN within the next 36 hours.

b. With the containment sump level monitoring system inoperable, restore the inoperable system to OPERABLE status within 7 days or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The leakage detection systems shall be demonstrated OPERABLE by:

a. Containment atmosphere gaseous and particulate monitoring systems-performance of CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies specified in Table 4.3-3, and

b. Containment sump level monitoring system-performance of CHANNEL CALIBRATION TEST at least once per 18 months.

REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 GPM UNIDENTIFIED LEAKAGE,

c. 0.035 GPM primary-to-secondary leakage through any one steam generator, and

d. 10 GPM IDENTIFIED LEAKAGE from the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in COLD SHUTDOWN within 36 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE, reduce the leakage rate to within limits within 4 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System IDENTIFIED LEAKAGE and UNIDENTIFIED LEAKAGE shall be demonstrated to be within limits by performance of a Reactor Coolant System water inventory balance at least once per 72 hours during steady state operation except when operating in the shutdown cooling mode.

4.4.6.2.2 Primary to secondary leakage shall be demonstrated to be within the above limits by performance of a primary to secondary leak rate determination at least once per 72 hours. The provisions of Specification 4.0.4 are not applicable for entry into MODE 4.

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

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

a. $\leq$ 1.0 μCi/gram DOSE EQUIVALENT I-131, and

b. $\leq 100/\bar{E}$ μCi/gram of gross specific activity.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTION:

MODES 1, 2, and 3*:

a. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 but within the allowable limit (below and to the left of the line) shown on Figure 3.4-1, operation may continue for up to 48 hours. Specification 3.0.4 is not applicable.

b. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in HOT STANDBY with T_{avg} < 515°F within 4 hours.

c. With the specific activity of the primary coolant $> 100/\bar{E}$ μCi/gram of gross specific activity, be in HOT STANDBY with T_{avg} < 515°F within 4 hours.

MODES 1, 2, 3, 4 and 5:

d. With the specific activity of the primary coolant > 1.0 μCi/gram DOSE EQUIVALENT I-131 or $> 100/\bar{E}$ μCi/gram of gross specific activity, perform the sampling and analysis requirements of item 4 a) of Table 4.4-2 until the specific activity of the primary coolant is restored to within its limits.

*With $T_{avg} \geq$ 515°F.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-2.

TABLE 4.4-2

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY
1. Gross Activity Determination	3 times per 7 days with a maximum time of 72 hours between samples
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days
3. Radiochemical Analysis for $\bar{E}$ Determination	1 per 6 months*
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135.	a) Once per 4 hours, whenever the specific activity exceeds 1.0 μCi/gram, DOSE EQUIVALENT I-131, or 100/$\bar{E}$ μCi/gram of gross specific activity, and b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.

* 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. The provisions of Specification 4.0.4 are not applicable.

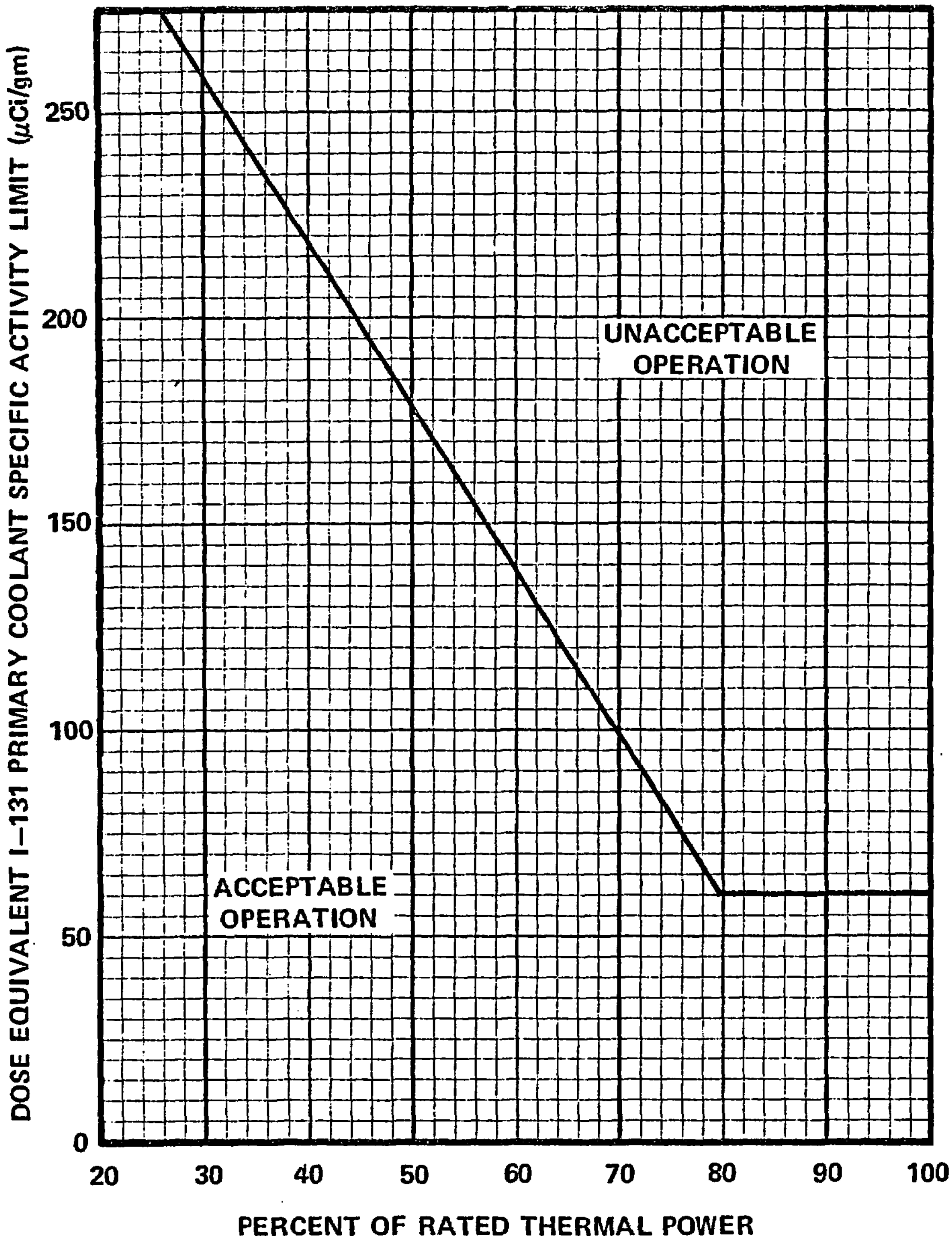


FIGURE 3.4-1

DOSE EQUIVALENT I–131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity > 1.0μCi/gram Dose Equivalent I-131

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.9.1 Reactor Coolant System (except the pressurizer) temperature, pressure, and heatup and cooldown rates shall be limited in accordance with the limits specified in Table 3.4-2 and shown on Figures 3.4-2a and 3.4-2b.

APPLICABILITY: At all times.

ACTION:

a. With any of the above limits exceeded in MODES 1, 2, 3, or 4, perform the following:

   1. Restore the temperature and/or pressure to within limit within 30 minutes.

      AND

   2. Perform an engineering evaluation to determine the effects of the out of limit condition on the structural integrity of the Reactor Coolant System and determine that the Reactor Coolant System remains acceptable for continued operation within 72 hours. Otherwise, be in at least MODE 3 within the next 6 hours and in MODE 5 with RCS pressure less than 300 psia within the following 30 hours.

b. With any of the above limits exceeded in other than MODES 1, 2, 3, or 4, perform the following:

   1. Immediately initiate action to restore the temperature and/or pressure to within limit.

      AND

   2. Perform an engineering evaluation to determine the effects of the out of limit condition on the structural integrity of the Reactor Coolant System and determine that the Reactor Coolant System is acceptable for continued operation prior to entering MODE 4.

SURVEILLANCE REQUIREMENTS

4.4.9.1

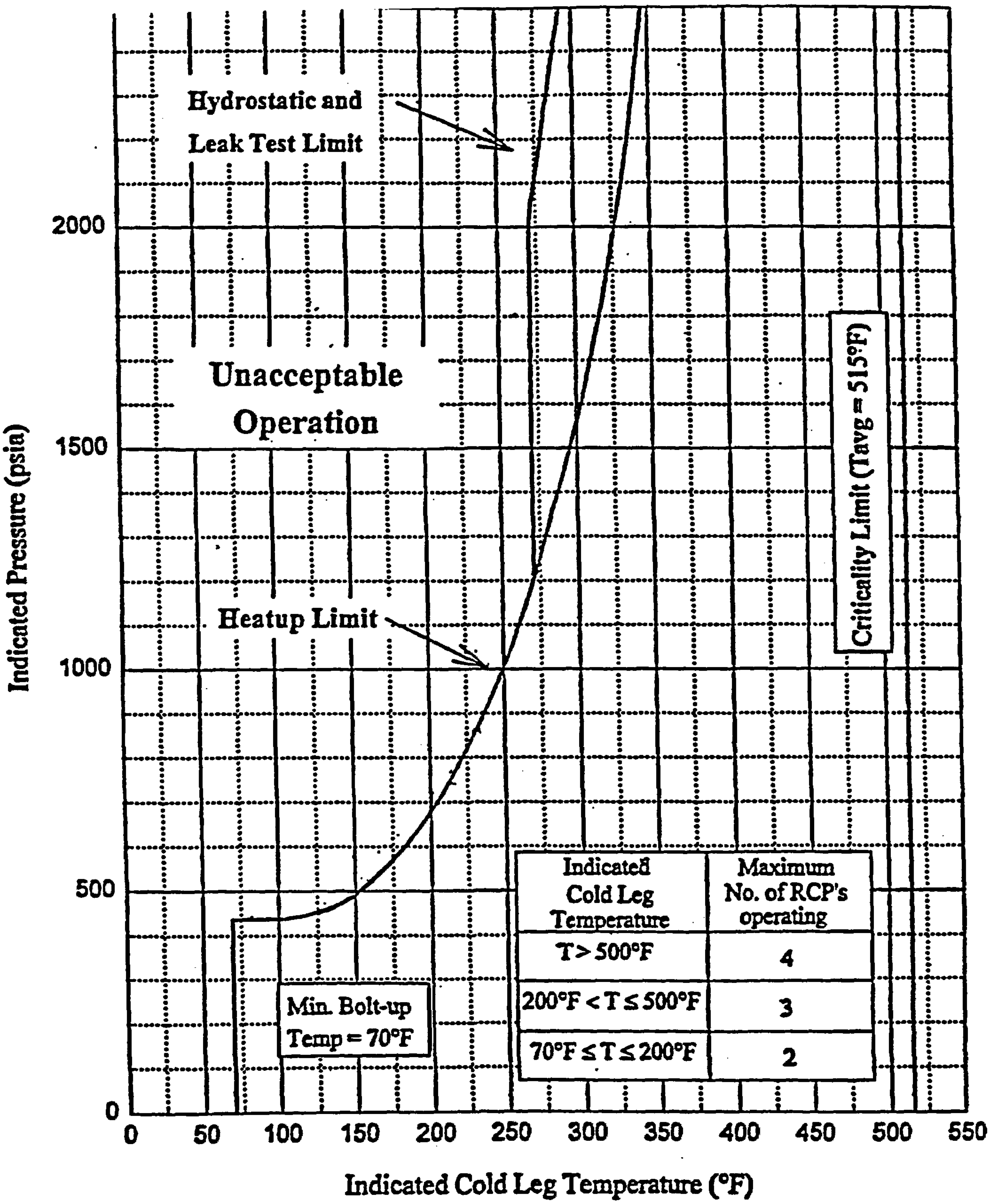
a. The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

b. DELETED

TABLE 3.4-2

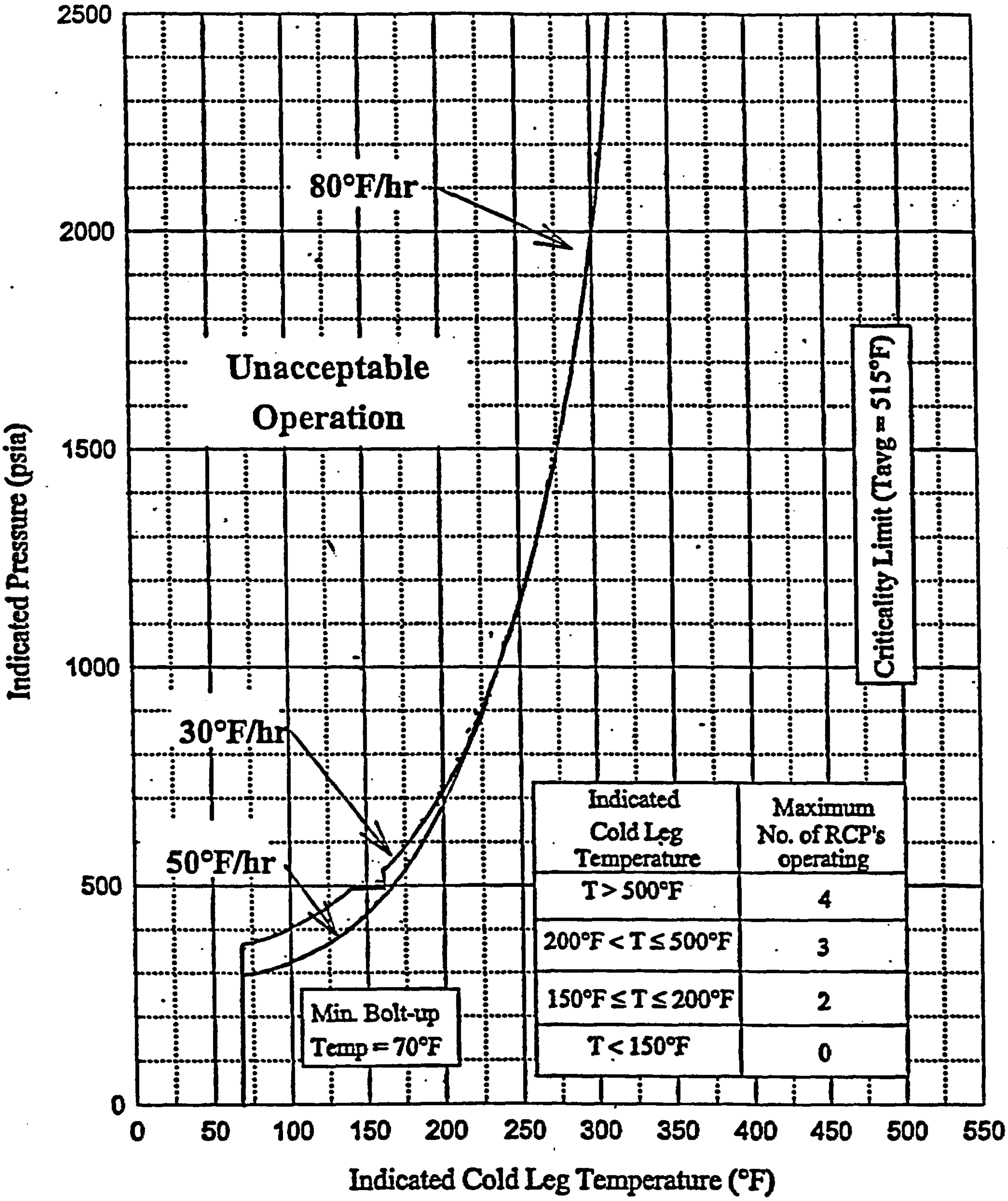
REACTOR COOLANT SYSTEM
HEATUP AND COOLDOWN LIMITS

Cooldown		Heatup	
Indicated Cold Leg Temperature	Limit	Indicated Cold Leg Temperature	Limit
≤ 100°F	≤ 5°F/hour if RCS not vented.	≤ 220°F	≤ 30°F/hour
100°F < T ≤ 230°F	≤ 30°F/hour if RCS not vented.	220°F < T ≤ 275°F	≤ 50°F/hour
< 190°F	≤ 50°F/hour if RCS vent ≥ 2.2 square inches.	> 275°F	≤ 100°F/hour
≤ 230°F	≤ 50°F/hour during unanticipated temperature excursions.		
> 230°F	≤ 80°F/hour		
		Inservice Hydrostatic and Leak Testing	
		Indicated Cold Leg Temperature	≤ 5°F/hour for 1 hour prior to and during inservice hydrostatic and leak testing operations above the heatup limit curve.



Indicated Cold Leg Temperature	Maximum No. of RCP's operating
T > 500°F	4
200°F < T ≤ 500°F	3
70°F ≤ T ≤ 200°F	2

Millstone Unit 2 Reactor Coolant System
Heatup Limitations for Up to 20 EFPY
Figure 3.4-2a



Millstone Unit 2 Reactor Coolant System
Cooldown Limitations for Up to 20 EFPY
Figure 3.4-2b

THIS PAGE INTENTIONALLY LEFT BLANK

This page intentionally left blank

LIMITING CONDITION FOR OPERATION

3.4.9.3 A Low Temperature Overpressure Protection (LTOP) System, as specified below, shall be OPERABLE.

a. MODE 4, and MODE 5 with all RCS cold leg temperature > 190°F:

   1. Maximum of two charging pumps and one HPSI pump may be capable of injecting into the RCS; and
   2. Two OPERABLE PORVs with a lift setpoint of $\leq$ 415 psia.

b. MODE 5 with any RCS cold leg temperature $\leq$ 190 °F, and MODE 6 either:

   1. Maximum of one charging pump may be capable of injecting into the RCS; and
   2. Two OPERABLE PORVs with a lift setpoint of $\leq$ 415 psia.

   OR

   3. Maximum of two charging pumps and one HPSI pump may be capable of injecting into the RCS; and
   4. The RCS is depressurized and an RCS vent of $\geq$ 2.2 sq. inches.

APPLICABILITY: MODE 4 when the temperature of any RCS cold leg is less than or equal to 275°F, MODE 5, and MODE 6 when the head is on the reactor vessel.

ACTION:

a. With one required PORV inoperable in MODE 4, restore the inoperable PORV to OPERABLE status within 7 days or depressurize and vent the RCS through a $\geq$ 2.2 square inch vent within the next 8 hours.

b. With one required PORV inoperable in MODES 5 or 6, either restore inoperable PORV to OPERABLE status within 24 hours or depressurize and vent the RCS through a $\geq$ 2.2 square inch vent within the next 8 hours.

c. With both required PORVs inoperable, depressurize and vent the RCS through a $\geq$ 2.2 square inch vent within 8 hours.

d. With more than the maximum allowed pumps capable of injecting into the RCS, take immediate action to comply with 3.4.9.3.

e. In the event either the PORVs or the RCS vent(s) are used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence.

f. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENT

4.4.9.3.1 Each PORV shall be demonstrated OPERABLE by:

a. Performance of a CHANNEL FUNCTIONAL TEST on the PORV actuation channel, but excluding valve operation, within 31 days prior to entering a condition in which the PORV is required OPERABLE and at least once per 31 days thereafter when the PORV is required OPERABLE.

b. Performance of a CHANNEL CALIBRATION on the PORV actuation channel at least once per 18 months.

c. Verifying the PORV block valve is open at least once per 72 hours when the PORV is being used for overpressure protection.

d. Testing in accordance with the inservice test requirements of Specification 4.0.5.

4.4.9.3.2 Verify no more than the maximum allowed number of charging pumps are capable of injecting into the RCS at least once per 12 hours.

4.4.9.3.3 Verify no more than the maximum allowed number of HPSI pumps are capable of injecting into the RCS at least once per 12 hours.

4.4.9.3.4 Verify the required RCS vent is open at least once per 31 days when the vent pathway is provided by vent valve(s) that is(are) locked, sealed, or otherwise secured in the open position, otherwise, verify the vent pathway at least once per 12 hours.

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

SAFETY INJECTION TANKS (SITs)

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system SIT shall be OPERABLE with:

a. The isolation valve open and the power to the valve operator removed,

b. Between 1080 and 1190 cubic feet of borated water,

c. A minimum boron concentration of 1720 PPM, and

d. A nitrogen cover-pressure of between 200 and 250 psig.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. With one SIT inoperable due to boron concentration not within limits, restore boron concentration to within limits within 72 hours.

b. With one SIT inoperable due solely to inability to verify level or pressure, restore SIT to OPERABLE status within 72 hours.

c. With one SIT inoperable, except as a result of boron concentration not within limits or inoperable level or pressure instrumentation, restore SIT to OPERABLE status within 24 hours.

d. With required ACTION a. or b. or c. and associated Completion Time not met:

   1. Be in MODE 3 within 6 hours, and

   2. Reduce pressurizer pressure to < 1750 psia within 12 hours.

e. With two or more SITs inoperable, immediately enter LCO 3.0.3.

*With pressurizer pressure $\geq$ 1750 psia.

SURVEILLANCE REQUIREMENTS

4.5.1 Each SIT shall be demonstrated OPERABLE:

a. Verify each SIT isolation valve is fully open at least once per 12 hours.[1]

b. Verify borated water volume in each SIT is $\geq$ 1080 cubic feet and $\leq$ 1190 cubic feet at least once per 12 hours.[2]

c. Verify nitrogen cover-pressure in each SIT is $\geq$ 200 psig and $\leq$ 250 psig at least once per 12 hours.[3]

d. Verify boron concentration in each SIT is $\geq$ 1720 ppm at least once per 6 months, and once within 6 hours after each solution volume increase of $\geq$ 1% of tank volume[4] that is not the result of addition from the refueling water storage tank.

e. Verify that the closing coil in the valve breaker cubicle is removed at least once per 31 days.

(1) If one SIT is inoperable, except as a result of boron concentration not within limits or inoperable level or pressure instrumentation, surveillance is not applicable to the affected SIT.

(2) If one SIT is inoperable due solely to inoperable water level instrumentation, surveillance is not applicable to the affected SIT.

(3) If one SIT is inoperable due solely to inoperable pressure instrumentation, surveillance is not applicable to affected SIT.

(4) Only required to be performed for affected SIT.

EMERGENCY CORE COOLING SYSTEMS

ECCS SUBSYSTEMS - $T_{avg} \geq 300°F$

LIMITING CONDITION FOR OPERATION

3.5.2 Two ECCS subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1750 psia within the following 6 hours.

b. In the event the ECCS 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.

* With pressurizer pressure ≥ 1750 psia.

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying each Emergency Core Cooling System manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.

b. At least once per 31 days by verifying that the following valves are in the indicated position with power to the valve operator removed:

Valve Number	Valve Function	Valve Position
2-SI-306	Shutdown Cooling Flow Control	Open*
2-SI-659	SRAS Recirc.	Open**
2-SI-660	SRAS Recirc.	Open**

* Pinned and locked at preset throttle open position.

** To be closed prior to recirculation following LOCA.

c. By verifying the developed head of each high pressure safety injection pump at the flow test point is greater than or equal to the required developed head when tested pursuant to Specification 4.0.5.

d. By verifying the developed head of each low pressure safety injection pump at the flow test point is greater than or equal to the required developed head when tested pursuant to Specification 4.0.5.

e. By verifying the delivered flow of each charging pump at the required discharge pressure is greater than or equal to the required flow when tested pursuant to Specification 4.0.5.

f. At least once per 18 months by verifying each Emergency Core Cooling System automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

g. At least once per 18 months by verifying each high pressure safety injection pump and low pressure safety injection pump starts automatically on an actual or simulated actuation signal.

h. At least once per 18 months by verifying each low pressure safety injection pump stops automatically on an actual or simulated actuation signal.

i. By verifying the correct position of each electrical and/or mechanical position stop for each injection valve in Table 4.5-1:

   1. Within 4 hours after completion of valve operations.

   2. At least once per 18 months.

j. At least once per 18 months by verifying through visual inspection of the containment sump that each Emergency Core Cooling System subsystem suction inlet is not restricted by debris and the suction inlet trash racks and screens show no evidence of structural distress or abnormal corrosion.

k. At least once per 18 months by verifying the Shutdown Cooling System open permissive interlock prevents the Shutdown Cooling System inlet isolation valves from being opened with an actual or simulated Reactor Coolant System pressure signal of ≥ 300 psia.

Page 3/4 5-5a has been removed from Tech Specs as a result of this LBDCR

Table 4.5-1

ECCS INJECTION VALVES

1.	2-SI-617	"A" HPSI Header - Loop 1A Injection
2.	2-SI-627	"A" HPSI Header - Loop 1B Injection
3.	2-SI-637	"A" HPSI Header - Loop 2A Injection
4.	2-SI-647	"A" HPSI Header - Loop 2B Injection
5.	2-SI-616	"B" HPSI Header - Loop 1A Injection
6.	2-SI-626	"B" HPSI Header - Loop 1B Injection
7.	2-SI-636	"B" HPSI Header - Loop 2A Injection
8.	2-SI-646	"B" HPSI Header - Loop 2B Injection
9.	2-SI-615	LPSI Header - Loop 1A Injection
10.	2-SI-625	LPSI Header - Loop 1B Injection
11.	2-SI-635	LPSI Header - Loop 2A Injection
12.	2-SI-645	LPSI Header - Loop 2B Injection

Page 3/4 5-6a has been removed from Tech Specs as a result of this LBDCR

ECCS SUBSYSTEMS - T_{avg} < 300°F

LIMITING CONDITION FOR OPERATION

3.5.3 One high pressure safety injection subsystem shall be OPERABLE.

NOTES

1. The provisions of Specifications 3.0.4 and 4.0.4 are not applicable for entry into MODE 4 for the high pressure safety injection pump that is inoperable pursuant to Specification 3.4.9.3 provided the high pressure safety injection pump is restored to OPERABLE status within 1 hour after entering MODE 4.

2. In MODE 4, the requirement for OPERABLE safety injection and sump recirculation actuation signals is satisfied by use of the safety injection and sump recirculation trip pushbuttons.

3. In MODE 4, the OPERABLE HPSI pump is not required to start automatically on a SIAS. Therefore, the pump control switch for this OPERABLE pump may be placed in the pull-to-lock position without affecting the OPERABILITY of this pump.

APPLICABILITY: MODES 3* and 4.

ACTION:

a. With no high pressure safety injection subsystem OPERABLE, restore at least one high pressure safety injection subsystem to OPERABLE status within one hour or be in COLD SHUTDOWN within the next 24 hours.

b. In the event the ECCS 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.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The high pressure safety injection subsystem shall be demonstrated OPERABLE per the applicable portions of Surveillance Requirements 4.5.2.a, 4.5.2.b, 4.5.2.c, 4.5.2.f, 4.5.2.g, 4.5.2.i, and 4.5.2.j.

*With pressurizer pressure < 1750 psia.

THIS PAGE INTENTIONALLY DELETED

REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.4 The refueling water storage tank shall be OPERABLE with:

a. A minimum contained volume of 370,000 gallons of borated water,

b. A minimum boron concentration of 1720 ppm,

c. A minimum water temperature of 50°F when in MODES 1 and 2, and

d. A minimum water temperature of 35°F when in MODES 3 and 4.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the refueling water storage tank inoperable, restore tank to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The RWST shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the water level in the tank, and

2. Verifying the boron concentration of the water.

b. When in MODES 3 and 4, at least once per 24 hours by verifying the RWST temperature is $\geq$ 35°F when the RWST ambient air temperature is < 35°F.

c. When in MODES 1 and 2, at least once per 24 hours by verifying the RWST temperature is $\geq$ 50°F when the RWST ambient air temperature is < 50°F.

EMERGENCY CORE COOLING SYSTEMS

TRISODIUM PHOSPHATE (TSP)

LIMITING CONDITION FOR OPERATION

3.5.5 The TSP baskets shall contain $\geq$282 ft^3 of active TSP.

APPLICABILITY: MODES 1, 2, and 3

ACTION:

With the quantity of TSP less than required, restore the TSP quantity within 48 hours, or be in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.5.1 Verify that the TSP baskets contain $\geq$282 ft^3 of granular trisodium phosphate dodecahydrate at least once per 18 months.

4.5.5.2 Verify that a sample from the TSP baskets provides adequate pH adjustment of borated water at least once per 18 months.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that all penetrations [1] not capable of being closed by OPERABLE containment automatic isolation valves [2] and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions, [3] except for valves that are open under administrative control as permitted by Specification 3.6.3.1.

b. At least once per 31 days by verifying the equipment hatch is closed and sealed.

c. By verifying the containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. After each closing of a penetration subject to type B testing (except the containment air lock), if opened following a Type A or B test, by leak rate testing in accordance with the Containment Leakage Rate Testing Program.

e. By verifying structural integrity in accordance with the Containment Tendon Surveillance Program.

---

(1) Except valves, blind flanges, and deactivated automatic valves which are located inside the containment and are locked, sealed, or otherwise secured in the closed position. These penetrations shall be verified closed prior to entering MODE 4 from MODE 5, if not performed within the previous 92 days.

(2) In MODE 4, the requirement for an OPERABLE containment automatic isolation valve system is satisfied by use of the containment isolation trip pushbuttons

(3) Isolation devices in high radiation areas may be verified by use of administrative means.

CONTAINMENT SYSTEMS

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate of $< L_a$, 0.50 percent by weight of the containment air per 24 hours at P_a, 54 psig.

b. A combined leakage rate of $< 0.60\ L_a$ for all penetrations and valves subject to Type B and C tests when pressurized to P_a.

c. A combined leakage rate of $< 0.0072\ L_a$ for all penetrations that are secondary containment bypass leakage paths when pressurized to P_a.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With either (a) the measured overall integrated containment leakage rate exceeding $0.75\ L_a$, or (b) with the measured combined leakage rate for all penetrations and valves subject to Types B and C tests exceeding $0.60\ L_a$, or (c) with the combined bypass leakage rate exceeding $0.0072\ L_a$, restore the leakage rate(s) to within the limit(s) prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated in accordance with the Containment Leakage Rate Testing Program.

This Page Intentionally Deleted

This Page Intentionally Deleted

This Page Intentionally Deleted.

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 The 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 $\leq$ 0.05 L_a at P_a (54 psig).

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

NOTE
Entry and exit through the containment air lock doors is permitted to perform repairs on the affected air lock components.

a. With only one containment air lock door inoperable:

1. Verify the OPERABLE air lock door is closed within 1 hour 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 STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

4. Entry into an OPERATIONAL MODE or other specified condition under the provisions of Specification 3.0.4 shall not be made if the inner air lock door is inoperable.

b. With only the containment air lock interlock mechanism inoperable, verify an OPERABLE air lock door is closed within 1 hour and lock an OPERABLE air lock door closed within 24 hours. Verify an OPERABLE air lock door is locked closed at least once per 31 days thereafter. Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. (Entry into and exit from containment is permissible under the control of a dedicated individual).

c. With the containment air lock inoperable, except as specified in ACTION a. or ACTION b. above, immediately initiate action to evaluate overall containment leakage rate per Specification 3.6.1.2 and verify an air lock door is closed within 1 hour. Restore the air lock to OPERABLE status within 24 hours. Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

CONTAINMENT SYSTEMS

CONTAINMENT AIR LOCKS

SURVEILLANCE REQUIREMENTS

4.6.1.3.1 Each containment air lock shall be demonstrated OPERABLE in accordance with the Containment Leakage Rate Testing Program. Containment air lock leakage test results shall be evaluated against the leakage limits of Technical Specification 3.6.1.2. (An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test).

4.6.1.3.2 Each containment air lock shall be demonstrated OPERABLE at least once per 24 months by verifying that only one door in each air lock can be opened at a time.

This Page Intentionally Deleted

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -12 inches Water Gauge and +1.0 PSIG.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment internal pressure in excess of or below the limits above, restore the internal pressure to within the limits within 1 hour or be in HOT STANDBY within the next 4 hours; go to COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to within the limits at least once per 12 hours.

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall not exceed 120°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment average air temperature > 120°F, reduce the average air temperature to within the limit within 8 hours, or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 The primary containment average air temperature shall be determined to be $\leq$ 120°F at least once per 24 hours.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

CONTAINMENT SPRAY AND COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.2.1 Two containment spray trains and two containment cooling trains, with each cooling train consisting of two containment air recirculation and cooling units, shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION: :

Inoperable Equipment	Required Action
a. One containment spray train	a.1 Restore the inoperable containment spray train to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and reduce pressurizer pressure to less than 1750 psia within the following 6 hours.
b. One containment cooling train	b.1 Restore the inoperable containment cooling train to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.
c. One containment spray train AND One containment cooling train	c.1 Restore the inoperable containment spray train or the inoperable containment cooling train to OPERABLE status within 48 hours or be in HOT SHUTDOWN within the next 12 hours.
d. Two containment cooling trains	d.1 Restore at least one inoperable containment cooling train to OPERABLE status within 48 hours or be in HOT SHUTDOWN within the next 12 hours.
e. All other combinations	e.1 Enter LCO 3.0.3 immediately.

SURVEILLANCE REQUIREMENTS

4.6.2.1.1 Each containment spray train shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying each containment spray manual, power operated, and automatic valve in the spray train flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.

* The Containment Spray System is not required to be OPERABLE in MODE 3 if pressurizer pressure is < 1750 psia.

b. By verifying the developed head of each containment spray pump at the flow test point is greater than or equal to the required developed head when tested pursuant to Specification 4.0.5.

c. At least once per 18 months by verifying each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

d. At least once per 18 months by verifying each containment spray pump starts automatically on an actual or simulated actuation signal.

e. At least once per 10 years by verifying each spray nozzle is unobstructed.

4.6.2.1.2 Each containment air recirculation and cooling unit shall be demonstrated OPERABLE:

a. At least once per 31 days by operating each containment air recirculation and cooling unit in slow speed for $\geq$ 15 minutes.

b. At least once per 31 days by verifying each containment air recirculation and cooling unit cooling water flow rate is $\geq$ 500 gpm.

c. At least once per 18 months by verifying each containment air recirculation and cooling unit starts automatically on an actual or simulated actuation signal.

THIS PAGE
INTENTIONALLY LEFT BLANK

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3.1 Each containment isolation valve shall be OPERABLE. (1) (2)

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the isolation valve(s) inoperable, either:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

b. Isolate the affected penetration(s) within 4 hours by use of a deactivated automatic valve(s) secured in the isolation position(s), or

c. Isolate the affected penetration(s) within 4 hours by use of a closed manual valve(s) or blind flange(s); or

d. Isolate the affected penetration that has only one containment isolation valve and a closed system within 72 hours by use of at least one closed and deactivated automatic valve, closed manual valve, or blind flange; or

e. Be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each containment isolation valve shall be demonstrated OPERABLE:

a. By verifying the isolation time of each power operated automatic containment isolation valve when tested pursuant to Specification 4.0.5.

b. At least once per 18 months by verifying each automatic containment isolation valve that is not locked, sealed, or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.

---

(1) Containment isolation valves may be opened on an intermittent basis under administrative controls.

(2) The provisions of this Specification in MODES 1, 2 and 3, are not applicable for main steam line isolation valves. However, provisions of Specification 3.7.1.5 are applicable for main steam line isolation valves.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.3.2 The containment purge supply and exhaust isolation valves shall be sealed closed.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one containment purge supply and/or one exhaust isolation valve open, close the open valve(s) within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.2 The containment purge supply and exhaust isolation valves shall be determined sealed closed at least once per 31 days.

3/4.6.4 COMBUSTIBLE GAS CONTROL

DELETED

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

This Page Intentionally Left Blank.

POST-INCIDENT RECIRCULATION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.4.4 Two separate and independent post-incident recirculation systems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTION:

With one post-incident recirculation system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in HOT STANDBY within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.6.4.4 Each post-incident recirculation system shall be demonstrated OPERABLE at least once per 92 days on a STAGGERED TEST BASIS by:

a. Verifying that the system can be started on operator action in the control room, and

b. Verifying that the system operates for at least 15 minutes.

ENCLOSURE BUILDING FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.5.1 Two separate and independent Enclosure Building Filtration Trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one Enclosure Building Filtration Train inoperable, restore the inoperable train to OPERABLE status within 7 days or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1 Each Enclosure Building Filtration Train 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 filter and charcoal absorber train and verifying that the train operates for at least 10 hours with the heaters on.

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

SURVEILLANCE REQUIREMENTS (Continued)

1. Verifying that the cleanup train 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 train flow rate is 9000 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 train flow rate of 9000 cfm ± 10% during train 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. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is ≤ 2.6 inches Water Gauge while operating the train at a flow rate of 9000 cfm ± 10%.

2. Verifying that the train starts on an Enclosure Building Filtration Actuation Signal (EBFAS).

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% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the train at a flow rate of 9000 cfm ± 10%.

* ASTM D3803-89 shall be used in place of ANSI N509-1976 as referenced in table 2 of Regulatory Guide 1.52. The laboratory test of charcoal should be conducted at a temperature of 30°C and a relative humidity of 95% within the tolerances specified by ASTM D3803-89. Additionally, the charcoal sample shall have a removal efficiency of ≥ 95%.

SURVEILLANCE REQUIREMENTS (Continued)

f. After each complete or partial replacement of a charcoal absorber bank by verifying that the charcoal absorbers remove greater than or equal to 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the train at a flow rate of 9000 cfm ± 10%.

LIMITING CONDITION FOR OPERATION

3.6.5.2 The Enclosure Building shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the Enclosure Building inoperable, restore the Enclosure Building to OPERABLE status within 24 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.2.1 OPERABILITY of the Enclosure Building shall be demonstrated at least once per 31 days by verifying that each access opening is closed except when the access opening is being used for normal transit entry and exit.

4.6.5.2.2. At least once per 18 months verify each Enclosure Building Filtration Train produces a negative pressure of greater than or equal to 0.25 inches W.G. in the Enclosure Building Filtration Region within 1 minute after an Enclosure Building Filtration Actuation Signal.

3/4.7 PLANT SYSTEMS

3.4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 4.7-1.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or more required main steam line code safety valves per steam generator inoperable,

   1. Reduce THERMAL POWER within 4 hours to less than or equal to the applicable percent of RATED THERMAL POWER listed in Table 3.7-1, and

   2. Reduce the Power Level-High trip setpoint in accordance with Table 3.7-1 within 36 hours.

   Otherwise, be in HOT STANDBY within the next 6 hours, and HOT SHUTDOWN within the following 6 hours.

b. With more than four main steam line code safety valves on a single steam generator inoperable, be in HOT STANDBY within 6 hours, and HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Each main steam line code safety valve shall be demonstrated OPERABLE, with lift settings as shown in Table 4.7-1, in accordance with Specification 4.0.5.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE MAIN STEAM LINE CODE SAFETY VALVES (MSSVs)

MINIMUM NUMBER OF MSSVs PER STEAM GENERATOR REQUIRED OPERABLE	MAXIMUM POWER (Percent Of RATED THERMAL POWER)	MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT (Percent Of RATED THERMAL POWER)
8	100	106.6 (Ceiling)
7	85	94.6
6	75	84.6
5	60	69.6
4	45	54.6

TABLE 4.7-1

STEAM LINE SAFETY VALVES

VALVE NUMBERS	LIFT SETTING* (± 3%)**
a. 2-MS-246 & 2-MS-247	1000 psia
b. 2-MS-242 & 2-MS-254	1005 psia
c. 2-MS-245 & 2-MS-249	1015 psia
d. 2-MS-241 & 2-MS-252	1025 psia
e. 2-MS-244 & 2-MS-251	1035 psia
f. 2-MS-240 & 2-MS-250	1045 psia
g. 2-MS-239, 2-MS-243, 2-MS-248 & 2-MS-253	1050 psia

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** The lift setting shall be within ± 1% following main steam line code safety valve testing.

AUXILIARY FEEDWATER PUMPS

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three steam generator auxiliary feedwater pumps shall be OPERABLE with:

a. Two feedwater pumps capable of being powered from separate OPERABLE emergency busses, and

b. One feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective action to restore at least one auxiliary feedwater pump to OPERABLE status as soon as possible. Entry into an OPERATIONAL MODE or other specified condition under the provisions of Specification 3.0.4 shall not be made with three auxiliary feedwater pumps inoperable.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying each auxiliary feedwater manual, power operated, and automatic valve in each water flow path and in each steam supply flow path to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.

b. By verifying the developed head of each auxiliary feedwater pump at the flow test point is greater than or equal to the required developed head when tested pursuant to Specification 4.0.5. (Not required to be performed for the steam turbine driven auxiliary feedwater pump until 24 hours after reaching 800 psig in the steam generators. The provisions of Specification 4.0.4 are not applicable to the steam turbine driven auxiliary feedwater pump for entry into MODE 3.)

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by verifying each auxiliary feedwater automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position, as designed, on an actual or simulated actuation signal.

d. At least once per 18 months by verifying each auxiliary feedwater pump starts automatically, as designed, on an actual or simulated actuation signal.

e. By verifying the proper alignment of the required auxiliary feedwater flow paths by verifying flow from the condensate storage tank to each steam generator prior to entering MODE 2 whenever the unit has been in MODE 5, MODE 6, or defueled for a cumulative period of greater than 30 days.

PLANT SYSTEMS

CONDENSATE STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The condensate storage tank shall be OPERABLE with a minimum contained volume of 165,000 gallons.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With less than 165,000 gallons of water in the condensate storage tank, within 4 hours either:

a. Restore the water volume to within the limit or be in HOT SHUTDOWN within the next 12 hours, or

b. Demonstrate the OPERABILITY of the fire water system as a backup supply to the auxiliary feedwater pumps and restore the condensate storage tank water volume to within its limits within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The condensate storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level.

ACTIVITY

LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the secondary coolant system shall be $\leq$ 0.10 μCi/gram DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the specific activity of the secondary coolant system > 0.10 μCi/gram DOSE EQUIVALENT I-131, be in COLD SHUTDOWN within 36 hours after detection.

SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the secondary coolant system shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-2.

TABLE 4.7-2

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	MINIMUM FREQUENCY
1. Gross Activity Determination	3 times per 7 days with a maximum time of 72 hours between samples.
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	a) 1 per 31 days, whenever the gross activity determination indicates iodine concentrations greater than 10% of the allowable limit.
	b) 1 per 6 months, whenever the gross activity determination indicates iodine concentrations below 10% of the allowable limit.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.5 Each main steam line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

MODE 1 - With one main steam line isolation valve inoperable, POWER OPERATION may continue provided the inoperable valve is either restored to OPERABLE status or closed within 4 hours; otherwise, be in MODE 2 within the next 6 hours.

MODES 2 and 3 - With one or more main steam line isolation valves inoperable, subsequent operation in MODES 2 or 3 may continue provided the inoperable valve(s) is(are) restored to OPERABLE status or the isolation valve(s) is(are) closed* within 1 hour and verified closed at least once per 7 days; otherwise, be in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.5 Each main steam line isolation valve shall be demonstrated OPERABLE by verifying full closure within 6 seconds on any closure actuation signal while in HOT STANDBY, with $T_{avg} \geq 515°F$ during each plant startup except that verification of full closure within 6 seconds need not be determined more often than once per 92 days. The provisions of Technical Specification 4.0.4 do not apply for entry into MODE 3.

*The main steam line isolation valves may be opened to perform Surveillance Requirement 4.7.1.5.

MAIN FEEDWATER ISOLATION COMPONENTS (MFICs)

LIMITING CONDITION FOR OPERATION

3.7.1.6 Each feedwater isolation component listed in Table 3.7-3 shall be OPERABLE.

FW Isolation Components	Description
FW-38A	A FP Discharge MOV
FW-38B	B FP Discharge MOV
FW-42A	A FW Block MOV
FW-42B	B FW Block MOV
FW-41A	A FW Regulating Bypass Valve
FW-41B	B FW Regulating Bypass Valve
FW-51A	A FW Regulating Valve
FW-51B	B FW Regulating Valve
H5A	A SG Feedwater Pump Trip Circuitry
H5B	B SG Feedwater Pump Trip Circuitry

Table 3.7-3

APPLICABILITY: MODES 1, 2 & 3

ACTION:

a. With one feedwater isolation component inoperable in either or both feedwater flow paths, either:

   1. Restore the inoperable component(s) to OPERABLE status within 72 hours, or

   2. Close or isolate the inoperable feedwater isolation valve(s) within 72 hours, and verify that the inoperable feedwater isolation valve(s) is closed or isolated once per 7 days, or

   3. Secure or isolate the feedwater pump(s) with inoperable feedwater pump trip circuitry within 72 hours and verify that the inoperable feedwater pump(s) is secured or isolated once per 7 days, or

   4. Be in HOT SHUTDOWN within the next 12 hours.

b. With two or more of the feedwater isolation components inoperable in the same flow path, either:

1. Restore the inoperable component(s) to OPERABLE status within 8 hours until Action 'a' applies, or

2. Isolate the affected flow path within 8 hours, and verify that the inoperable feedwater isolation components are closed or isolated/secured once per 7 days, or

3. Be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.6 Each feedwater isolation valve/feedwater pump trip circuitry shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that on 'A' main steam isolation test signal, each isolation valve actuates to its isolation position, and

b. Verifying that on 'B' main steam isolation test signal, each isolation valve actuates to its isolation position, and

c. Verifying that on 'A' main steam isolation test signal, each feedwater pump trip circuit actuates, and

d. Verifying that on 'B' main steam isolation test signal, each feedwater pump trip circuit actuates.

PLANT SYSTEMS

ATMOSPHERIC DUMP VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.7 Each atmospheric dump valve line shall be OPERABLE.

APPLICABILITY MODES 1, 2, and 3.

ACTION:

a. With one atmospheric dump valve line inoperable, restore the inoperable line to OPERABLE status within 48 hours or be in MODE 3 within the next 6 hours and MODE 4 within the following 24 hours.

b. With more than one atmospheric dump valve line inoperable, restore one inoperable line to OPERABLE status within 1 hour or be in MODE 3 within the next 6 hours and MODE 4 within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.7 Verify the OPERABILITY of each atmospheric dump valve line by local manual operation of each valve in the flowpath through one complete cycle of operation at least once per 18 months.

STEAM GENERATOR BLOWDOWN ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.8 Each steam generator blowdown isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTION:

With one or more steam generator blowdown isolation valves inoperable, either:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours; or

b. Isolate the affected steam generator blowdown line within 4 hours; or

c. Be in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.8 Verify the closure time of each steam generator blowdown isolation valve is $\leq$ 10 seconds on an actual or simulated closure signal at least once per 18 months.

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.7.3 REACTOR BUILDING CLOSED COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3.1 Two reactor building closed cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one reactor building closed cooling water loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.7.3.1 Each reactor building closed cooling water loop shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying each reactor building closed cooling water manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.

b. At least once per 18 months by verifying each reactor building closed cooling water automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

c. At least once per 18 months by verifying each reactor building closed cooling water pump starts automatically on an actual or simulated actuation signal.

3/4.7.4 SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 Two service water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one service water loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 Each service water loop shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying each service water manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.

b. At least once per 18 months by verifying each service water automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

c. At least once per 18 months by verifying each service water pump starts automatically on an actual or simulated actuation signal.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 Two independent Control Room Emergency Ventilation Trains shall be OPERABLE.*

APPLICABILITY: MODES 1, 2, 3, 4, 5 and 6.

During irradiated fuel movement within containment or the spent fuel pool.

ACTION:

MODES 1, 2, 3, and 4:

a. With one Control Room Emergency Ventilation Train inoperable, restore the inoperable train to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With both Control Room Emergency Ventilation Trains inoperable, except as specified in ACTION c., immediately suspend the movement of irradiated fuel assemblies within the spent fuel pool. Restore at least one inoperable train to OPERABLE status within 1 hour, or be in HOT STANDBY within the next 6 hours, and COLD SHUTDOWN within the following 30 hours.

c. With both Control Room Emergency Ventilation Trains inoperable due to an inoperable Control Room boundary, immediately suspend the movement of irradiated fuel assemblies within the spent fuel pool. Restore the Control Room boundary to OPERABLE status within 24 hours or be in HOT STANDBY within the next 6 hours, and COLD SHUTDOWN within the following 30 hours.

* The Control Room boundary may be opened intermittently under administrative control.

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

ACTION (continued)

MODES 5 and 6, and during irradiated fuel movement within containment or the spent fuel pool:**

d. With one Control Room Emergency Ventilation Train inoperable, restore the inoperable train to OPERABLE status within 7 days. After 7 days, either initiate and maintain operation of the remaining OPERABLE Control Room Emergency Ventilation Train in the recirculation mode of operation, or immediately suspend CORE ALTERATIONS, and the movement of irradiated fuel assemblies.

e. With both Control Room Emergency Ventilation Trains inoperable, or with the OPERABLE Control Room Emergency Ventilation Train required to be in the recirculation mode by ACTION d. not capable of being powered by an OPERABLE normal and emergency power source, immediately suspend CORE ALTERATIONS, and the movement of irradiated fuel assemblies.

** In MODES 5 and 6, when a Control Room Emergency Ventilation Train is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered OPERABLE for the purpose of satisfying the requirements of 3.7.6.1 Limiting Condition for Operation, provided: (1) its corresponding normal or emergency power source is OPERABLE; and (2) all of its redundant system (s), subsystem (s), train (s), component (s) and device(s) are OPERABLE, or likewise satisfy the requirements of the specification. Unless both conditions (1) and (2) are satisfied within 2 hours, then ACTION 3.7.6.1.d or 3.7.6.1.e shall be invoked as applicable.

SURVEILLANCE REQUIREMENTS

4.7.6.1 Each Control Room Emergency Ventilation Train shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the control room air temperature is $\leq$ 100°F.

b. At least once per 31 days on a STAGGERED TEST BASIS by initiating from the control room, flow through the HEPA filters and charcoal absorber train and verifying that the train operates for at least 15 minutes.

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

   1. Verifying that the cleanup train 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 train flow rate is 2500 cfm $\pm$ 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.* The carbon sample shall have a removal efficiency of $\geq$ 95 percent.

   3. Verifying a train flow rate of 2500 cfm $\pm$ 10% during train operation when tested in accordance with ANSI N510-1975.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory 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.*

---

* ASTM D3803-89 shall be used in place of ANSI N509-1976 as referenced in table 2 of Regulatory Guide 1.52. The laboratory test of charcoal should be conducted at a temperature of 30°C and a relative humidity of 95% within the tolerances specified by ASTM D3803-89.

SURVEILLANCE REQUIREMENTS (Continued)

e. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 3.4 inches Water Gauge while operating the train at a flow rate of 2500 cfm ± 10%.

2. Verifying that on a recirculation signal, with the Control Room Emergency Ventilation Train operating in the normal mode and the smoke purge mode, the train automatically switches into a recirculation mode of operation with flow through the HEPA filters and charcoal adsorber banks.

SURVEILLANCE REQUIREMENTS (Continued)

3. Verifying that control room air in-leakage is less than 130 SCFM with the Control Room Emergency Ventilation System operating in the recirculation/filtration mode.

f. 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% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the train at a flow rate of 2500 cfm ± 10%.

g. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove greater than or equal to 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the train at a flow rate of 2500 cfm ± 10%.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.7.8 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.8 All snubbers shall be OPERABLE. The only snubbers excluded from the requirements 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.

APPLICABILITY: MODES 1, 2, 3, and 4. MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES.

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 4.7.8.d on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for the system.

SURVEILLANCE REQUIREMENTS

4.7.8 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 categories (inaccessible and accessible) may be inspected independently according to the schedule determined by Table 4.7-3. The visual inspection interval for each type of snubber shall be determined based upon the criteria provided in Table 4.7-3 and the first inspection interval determined using this criteria shall be based upon the previous inspection interval as established by the requirements in effect before Amendment 160 .

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that (1) the snubber has no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are functional, and (3) fasteners for the attachment of the snubber to the component and to the snubber anchorage are functional. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable 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 that may be generically susceptible; and (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Specification 4.7.8.e or 4.7.8.f, as applicable. All snubbers found connected to an inoperable common hydraulic fluid reservoir shall be counted as unacceptable for determining the next inspection interval. A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the ACTION requirements shall be met.

d. Snubber Tests

At least once per eighteen (18) months during shutdown, a representative sample (10% of the total of each type of snubber, mechanical and hydraulic, in use in the plant) shall be tested either in place or in a bench test. For each snubber that does not meet the test acceptance criteria of Specification 4.7.8.e or 4.7.8.f, as applicable, an additional 5% of that type of snubber shall be tested.

Testing shall continue until no additional inoperable snubbers are found within a sample or until all snubbers have been tested. The representative sample selected for testing shall include the various configurations, and the range of size and capacity of snubbers.

Snubbers identified as "Especially Difficult to Remove" or in "High Radiation Zones During Shutdown" shall also be included in the representative sample.*

In addition to the regular sample, in locations where snubbers had failed the previous test due to operational or environmental conditions (excessive vibration, water hammer, high radiation, extreme heat or humidity, etc.), the snubbers currently installed in these locations shall be tested during the next test period. Test results of these snubbers may not be included for the resampling. All replacement snubbers shall have been tested prior to installation.

*Permanent or other exemptions from functional testing for individual snubbers in these categories may be granted by the Commission only if a justifiable basis for exemption is presented.

If any snubber selected for 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 design deficiency, all snubbers of the same design subject to the same defect shall be tested regardless of location or difficulty or removal. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the test acceptance criteria.

For the 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 the snubber (s) in order to ensure that the supported component remains capable of meeting the designed service.

e. 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.

f. 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.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

g. 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 Quality Assurance Program Topical Report.

*Mechanical snubber functional test acceptance criteria shall become effective upon installation of snubber testing equipment but not later than June 30, 1985.

SURVEILLANCE REQUIREMENT (Continued)

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each snubber 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 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.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

TABL .7-3

SNUBBER VISUAL INSPECTION INTERVAL

	NUMBER OF UNACCEPTABLE SNUBBERS		
Population or Category (Notes 1 and 2)	Column A Extend Interval (Notes 3 and 6)	Column B Repeat Interval (Notes 4 and 6)	Column C Reduce Interval (Notes 5 and 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, that decision must be made and documented before any inspection and that decision shall be used as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

3/4.7.9 Deleted

3/4.7.10 Deleted

3/4.7.11 ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.11 The ultimate heat sink shall be OPERABLE with a water temperature of less than or equal to 75°F.

APPLICABILITY: MODES 1, 2, 3, AND 4

ACTION:

a. With the ultimate heat sink water temperature > 75°F and ≤ 77°F, operation may continue provided the water temperature averaged over the previous 24 hour period is verified ≤ 75°F at least once per hour. Otherwise, be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With the ultimate heat sink water temperature > 77°F, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.11 The ultimate heat sink shall be determined OPERABLE:

a. At least once per 24 hours by verifying the water temperature to be within limits.

b. At least once per 6 hours by verifying the water temperature to be within limits when the water temperature exceeds 70°F.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 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. Two separate and independent diesel generators each with a separate fuel oil supply tank containing a minimum of 12,000 gallons of fuel.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Inoperable Equipment	Required Action
a. One offsite circuit	a.1 Perform Surveillance Requirement 4.8.1.1.1 for remaining offsite circuit within 1 hour prior to or after entering this condition, and at least once per 8 hours thereafter. AND a.2 Restore the inoperable offsite circuit to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

ACTION (Continued)

Inoperable Equipment	Required Action
b. One diesel generator	b.1 Perform Surveillance Requirement 4.8.1.1.1 for the offsite circuits within 1 hour prior to or after entering this condition, and at least once per 8 hours thereafter. AND b.2 Demonstrate OPERABLE diesel generator is not inoperable due to common cause failure within 24 hours or perform Surveillance Requirement 4.8.1.1.2.a.2 for the OPERABLE diesel generator within 24 hours. AND b.3 Verify the steam-driven auxiliary feedwater pump is OPERABLE (MODES 1, 2, and 3 only). If this condition is not satisfied within 2 hours, be in a least HOT STANDBY within the next 6 hours and HOT SHUTDOWN within the following 6 hours. AND b.4 (Applicable only if the 14 day allowed outage time specified in Action Statement b.5 is to be used.) Verify the required Millstone Unit No. 3 diesel generator(s) is/are OPERABLE and the Millstone Unit No. 3 SBO diesel generator is available within 1 hour prior to or after entering this condition, and at least once per 24 hours thereafter. Restore any inoperable required Millstone Unit No. 3 diesel generator to OPERABLE status and/or Millstone Unit No. 3 SBO diesel generator to available status within 72 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. AND b.5 Restore the inoperable diesel generator to OPERABLE status within 72 hours (within 14 days if Action Statement b.4 is met) or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

ACTION (Continued)

Inoperable Equipment	Required Action
c. One offsite circuit AND One diesel generator	c.1 Perform Surveillance Requirement 4.8.1.1.1 for remaining offsite circuit within 1 hour and at least once per 8 hours thereafter. AND c.2 Demonstrate OPERABLE diesel generator is not inoperable due to common cause failure within 8 hours or perform Surveillance Requirement 4.8.1.1.2.a.2 for the OPERABLE diesel generator within 8 hours. AND c.3 Verify the steam-driven auxiliary feedwater pump is OPERABLE (MODES 1, 2, and 3 only). If this condition is not satisfied within 2 hours, be in at least HOT STANDBY within the next 6 hours and HOT SHUTDOWN within the following 6 hours. AND c.4 Restore one inoperable A.C. source to OPERABLE status within 12 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. AND c.5 Restore remaining inoperable A.C. source to OPERABLE status following the time requirements of Action Statements a or b above based on the initial loss of the remaining inoperable A.C. source.
d. Two offsite circuits	d.1 Restore one of the inoperable offsite sources to OPERABLE status within 24 hours or be in HOT STANDBY within the next 6 hours. AND d.2 Following restoration of one offsite source restore remaining inoperable offsite source to OPERABLE status following the time requirements of Action Statement a above based on the initial loss of the remaining inoperable offsite source.

ACTION (Continued)

Inoperable Equipment	Required Action
e. Two diesel generators	e.1 Perform Surveillance Requirement 4.8.1.1.1 for the offsite circuits within 1 hour and at least once per 8 hours thereafter. AND e.2 Restore one of the inoperable diesel generators to OPERABLE status within 2 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. AND e.3 Following restoration of one diesel generator restore remaining inoperable diesel generator to OPERABLE status following the time requirements of Action Statement b above based on the initial loss of the remaining inoperable diesel generator.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Verify correct breaker alignment and indicated power available for each required offsite circuit at least once per 24 hours.

4.8.1.1.2 Each required diesel generator shall be demonstrated OPERABLE:*

a. At least once per 31 days by:

1. Verifying the fuel level in the fuel oil supply tank,

2.

NOTES

1. A modified diesel generator start involving idling and gradual acceleration to synchronous speed may be used as recommended by the manufacturer. When modified start procedures are not used, the requirements of SR 4.8.1.1.2.d.1 must be met.

2. Performance of SR 4.8.1.1.2.d satisfies this Surveillance Requirement.

Verifying the diesel generator starts from standby conditions and achieves steady state voltage ≥ 3740 V and ≤ 4580 V, and Frequency ≥ 58.8 Hz and ≤ 61.2 Hz.

3.

NOTES

1. Diesel generator loading may include gradual loading as recommended by the manufacturer.

2. Momentary transients outside the load range do not invalidate this test.

3. This test shall be conducted on only one diesel generator at a time.

4. This test shall be preceded by and immediately follow without shutdown a successful performance of SR 4.8.1.1.2.a.2, or SRs 4.8.1.1.2.d.1 and 4.8.1.1.2.d.2.

5. Performance of SR 4.8.1.1.2.d satisfies this Surveillance Requirement.

Verifying the diesel generator is synchronized and loaded, and operates for ≥ 60 minutes at a load ≥ 2475 kW and ≤ 2750 kW.

* All diesel starts may be preceded by an engine prelube period.

SURVEILLANCE REQUIREMENTS (Continued)

b. The diesel fuel oil supply shall be checked by:

1. Checking for and removing accumulated water from each fuel oil storage tank at least once per 92 days.

2. Verifying fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program in accordance with the Diesel Fuel Oil Testing Program.

c. At least once per 18 months by:

1. Deleted

2.

NOT E

This surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.

Verifying that the automatic time delay sequencer is OPERABLE with the following settings:

Sequence Step	Time After Closing of Diesel Generator Output Breaker (Seconds)	
	Minimum	Maximum
1 (T_1)	1.5	2.2
2 (T_2)	$T_1 + 5.5$	8.4
3 (T_3)	$T_2 + 5.5$	14.6
4 (T_4)	$T_3 + 5.5$	20.8

3.

> NOTE
>
> If performed with the diesel generator synchronized with offsite power, this surveillance shall be performed at a power factor ≤ 0.9 lagging. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable.

Verifying the diesel generator capability to reject a load greater than or equal to its associated single largest post-accident load and:

a) Following load rejection, the frequency is ≤ 63 Hz,

b) Within 2.2 seconds following load rejection, the voltage is ≥ 3740 V and ≤ 4580 V, and

c) Within 2.2 seconds following load rejection, the frequency is ≥ 58.8 Hz and ≤ 61.2 Hz.

4.

> NOTE
>
> If performed with the diesel generator synchronized with offsite power, this surveillance shall be performed at a power factor ≤ 0.83 lagging. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable.

Verifying the diesel generator does not trip following a load rejection of ≥ 2475 kW and ≤ 2750 kW.

5.

> NOTE
>
> This surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.

Verifying on an actual or simulated loss of offsite power in conjunction with an actual or simulated Engineered Safety Feature actuation signal:

a) De-energization of emergency buses,

b) Load shedding from emergency buses,

c) Diesel generator auto-starts from standby condition, and:

   1. energizes permanently connected loads in ≤ 15 seconds,
   2. energizes auto-connected loads through the load sequencer,
   3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V,
   4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz and,
   5. energizes permanently connected and auto-connected loads for ≥ 5 minutes.

6.

> NOTE
>
> This surveillance shall not normally be performed in MODE 1, 2, 3 or 4. However, this surveillance may be performed to reestablish OPERABILITY provided an assessment determines that safety of the plant is maintained or enhanced.

Verifying diesel generator automatic trips are bypassed on an actual or simulated loss of offsite power in conjunction with an actual or simulated Engineered Safety Feature actuation signal except:

a) Engine overspeed,

b) Generator differential current,

c) Voltage restraint overcurrent, and

d) Low lube oil pressure (switches to 2 out of 3 logic).

7.

NOTES
1. This surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.
2. The start of the diesel generator from a standby condition is not required if this surveillance is performed in conjunction with SR 4.8.1.1.2.c.5.

Verifying on an actual or simulated loss of offsite power signal:

a) De-energization of emergency buses,

b) Load shedding from emergency buses,

c) Diesel generator auto-starts from standby condition and:

1. energizes permanently connected loads in ≤ 15 seconds,
2. energizes auto-connected loads through the load sequencer,
3. achieves steady state voltage ≥ 3740 V and ≤ 4580 V,
4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz and,
5. energizes permanently connected and auto-connected loads for ≥ 5 minutes.

SURVEILLANCE REQUIREMENTS (Continued)

8. Verifying on an actual or simulated Engineered Safety Feature actuation signal the diesel generator auto-starts from a standby condition and:

   a) Achieves ≥ 90% of rated speed and ≥ 97% of rated voltage in ≤ 15 seconds,

   b) Achieves steady state voltage ≥ 3740 V and ≤ 4580 V,

   c) Achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz,

   d) Operates for ≥ 5 minutes,

   e) Permanently connected loads remain energized from the offsite power system, and

   f) Auto-connected loads remain energized from the offsite power system as appropriate for plant conditions.

9.

> NOTE
>
> This surveillance shall be performed within 5 minutes of shutting down the diesel generator after the diesel generator has operated ≥1 hour loaded ≥ 2475 kW and ≤ 2750 kW. Momentary transients outside the load range do not invalidate this test.

Verifying the diesel generator starts and:

   a) Accelerates to ≥ 90% of rated speed and ≥ 97% of rated voltage in ≤ 15 seconds, and

   b) Achieves steady state voltage ≥ 3740 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.

SURVEILLANCE REQUIREMENT (Continued)

d. At least once per 184 days by:

1. Verifying the diesel starts from standby conditions and accelerates to ≥ 90% of rated speed and to ≥ 97% of rated voltage within 15 seconds after the start signal.

2. Verifying the generator achieves steady state voltage ≥ 3740 V and ≤ 4580 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.

3.

NOTES

1. Diesel generator loading may include gradual loading as recommended by the manufacturer.
2. Momentary transients outside the load range do not invalidate this test.
3. This test shall be conducted on only one diesel generator at a time.
4. This test shall be preceded by and immediately follow without shutdown a successful performance of SRs 4.8.1.1.2.d.1 and 4.8.1.1.2.d.2, or SR 4.8.1.1.2.a.2.

Verifying the diesel generator is synchronized and loaded, and operates for ≥ 60 minutes at a load ≥ 2475 kW and ≤ 2750 kW.

ELECTRICAL POWER SYSTEMS

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. One diesel generator with a fuel oil supply tank containing a minimum of 12,000 gallons of fuel.

APPLICABILITY: MODES 5 and 6.

ACTION:

With less than the above minimum required A.C. electrical power sources OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes or movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.8.1.2 The above required A.C. electrical power sources shall be demonstrated OPERABLE per Surveillance Requirements 4.8.1.1.1 and 4.8.1.1.2, except for testing pursuant to Surveillance Requirements 4.8.1.1.2.a.3, 4.8.1.1.2.c.2, 4.8.1.1.2.c.5, 4.8.1.1.2.c.6, 4.8.1.1.2.c.7, and 4.8.1.1.2.d.3.

ELECTRICAL POWER SYSTEMS

3/4 8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A.C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generators with tie breakers open between redundant busses:

4160	volt Emergency Bus # 24 C
4160	volt Emergency Bus #24 D
480	volt Emergency Load Center #22 E
480	volt Emergency Load Center #22 F
120	volt A.C. Vital Bus # VA-10
120	volt A.C. Vital Bus # VA-20
120	volt A.C. Vital Bus # VA-30
120	volt A.C. Vital Bus # VA-40

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With less than the above complement of A.C. busses OPERABLE, restore the inoperable bus and/or associated load center to OPERABLE status within 8 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses shall be determined OPERABLE and energized from normal A.C. sources with tie breakers open between redundant busses at least once per 7 days by verifying correct breaker alignment and indicated power availability.

LIMITING CONDITION FOR OPERATION (Continued)

3.8.2.1A Inverters 5 and 6 shall be OPERABLE and available for automatic transfer via static switches VS1 and VS2 to power busses VA-10 and VA-20, respectively.

APPLICABILITY: MODES 1, 2 & 3

ACTION:

a. With inverter 5 or 6 inoperable, restore the inverter to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

b. With inverter 5 or 6 unavailable for automatic transfer via static switch VS1 or VS2 to power bus VA-10 or VA-20, respectively, restore the automatic transfer capability within 7 days or be in HOT SHUTDOWN within the next 12 hours.

c. With inverters 5 and 6 inoperable or unavailable for automatic transfer via static switches VS1 and VS2 to power busses VA-10 and VA-20, respectively, restore the inverters to OPERABLE status or restore their automatic transfer capability within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1A

a. Verify correct inverter voltage, frequency, and alignment for automatic transfer via static switches VS1 and VS2 to power busses VA-10 and VA-20, respectively, at least once per 7 days.

b. Verify that busses VA-10 and VA-20 automatically transfer to their alternate power sources, inverters 5 and 6, respectively, at least once per refueling during shutdown.

A.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, the following A.C. electrical busses shall be OPERABLE and energized from sources of power other than a diesel generator but aligned to an OPERABLE diesel generator:

1 - 4160 volt Emergency Bus

1 - 480 volt Emergency Load Center

2 - 120 volt A.C. Vital Busses

APPLICABILITY: MODES 5 and 6.

ACTION:

With less than the above complement of A.C. busses OPERABLE and energized, suspend all operations involving CORE ALTERATIONS or positive reactivity changes or movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.8.2.2 The specified A.C. busses shall be determined OPERABLE and energized from normal A.C. sources at least once per 7 days by verifying correct breaker alignment and indicated power availability.

ELECTRICAL POWER SYSTEMS

D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.3 125-volt D. C. bus Train A and 125-volt D. C. bus Train B electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one 125-volt D.C. bus train inoperable, restore the inoperable 125-volt D. C. bus train to OPERABLE status within 2 hours or be in COLD SHUTDOWN within the next 36 hours.

SURVEILLANCE REQUIREMENTS,

4.8.2.3.1 Each 125-volt D.C. bus train shall be determined OPERABLE at least once per 7 days by verifying correct breaker alignment and indicated power availability.

4.8.2.3.2 Each 125-volt D. C. battery bank and charger of Train A and Train B shall be demonstrated OPERABLE:

a. By verifying at least once per 7 days that the battery cell parameters meet Table 4.8-1 Category A limits.

b. By verifying at least once per 92 days the battery cell parameters meet Table 4.8-1 Category B limits.

SURVEILLANCE REQUIREMENTS (Continued)

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 deterioration that could degrade battery performance,

   2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material, and

   3. The battery charger will supply at least 400 amperes at a minimum of 130 volts for at least 12 hours.

d. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for 8 hours when the battery is subjected to a battery service test.

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. This performance discharge test may be performed in lieu of the battery service test.

SURVEILLANCE REQUIREMENTS (Continued)

Table 4.8-1
Battery Cell Parameters

Parameter	Category A: Limits For Each Designated Pilot Cell	Category B: Limits For Each Connected Cell
Electrolyte Level	Between the minimum and maximum level indication marks [(a)]	Not required.
Cell Voltage	$\geq$ 2.08 Volts	$\geq$ 2.08 Volts under float charge
Specific Gravity [(b)(c)]	$\geq$1.200 (Corrected to 77°F)	$\geq$1.200 (Corrected to 77°F)
Battery Voltage	$\geq$ 125 Volts (Overall voltage)	Not required.

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum during an equalizing charge provided it is not overflowing. Electrolyte level readings will be verified to meet the Category A limits within 7 days of completing an equalizing charge.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 5 amps when on float charge.

(c) A battery charging current of < 5 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

ELECTRICAL POWER SYSTEMS

D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.4 One 125-volt D. C. bus train electrical power subsystem shall be OPERABLE:

APPLICABILITY: MODES 5 and 6.

ACTION:

With no 125-volt D. C. bus trains OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes or movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.8.2.4.1 The above required 125-volt D.C. bus train shall be determined OPERABLE at least once per 7 days by verifying correct breaker alignment and indicated power availability.

4.8.2.4.2 The above required 125-volt D.C. bus train battery bank and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.3.2.

D.C. DISTRIBUTION SYSTEMS (TURBINE BATTERY) – OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.5 The Turbine Battery 125-volt D.C. electrical power subsystem shall be OPERABLE.

APPLICABILITY: MODES 1, 2 & 3

ACTION:

With the Turbine Battery 125-volt D.C. electrical power subsystem inoperable, restore the subsystem to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.5.1 Verify 125-volt D.C. bus 201D is OPERABLE at least once per 7 days.

4.8.2.5.2 125-volt D.C. battery bank 201D shall be demonstrated OPERABLE:

a. By verifying at least once per 7 days that the battery cell parameters meet Table 4.8-2 Category A limits.

b. By verifying at least once per 92 days the battery cell parameters meet Table 4.8-2 Category B limits.

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 deterioration that could degrade battery performance, and
   2. The cell-to-cell and terminal connections are clean, tight, free of corrosion, and coated with anti-corrosion material.

d. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual loads for 1 hour when the battery is subjected to a battery service test.

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. This performance discharge test may be performed in lieu of the battery service test.

SURVEILLANCE REQUIREMENTS (Continued)

Table 4.8-2
Turbine Battery Cell Parameters

Parameter	Category A: Limits For Each Designated Pilot Cell	Category B: Limits For Each Connected Cell
Electrolyte Level	Between the minimum and maximum level indication marks [a]	Not required.
Cell Voltage	$\geq$ 2.08 Volts	$\geq$ 2.08 Volts under float charge
Specific Gravity [b][c]	$\geq$ 1.200 (Corrected to 77°F)	$\geq$ 1.200 (Corrected to 77°F)
Battery Voltage	$\geq$ 125 Volts (Overall Voltage)	Not required.

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum during an equalizing charge provided it is not overflowing. Electrolyte level readings will be verified to meet the Category A limits within 7 days of completing an equalizing charge.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 5 amps when on float charge.

(c) A battery charging current of < 5 amps when on float charge is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 7 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 7 day allowance.

3/4.9.1 BORON CONCENTRATIONS

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained sufficient to ensure that the more restrictive of following reactivity conditions is met:

a. Either a K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to 1720 ppm.

APPLICABILITY: MODE 6.

NOTE
Only applicable to the refueling canal when connected to the Reactor Coolant System

ACTION:

With the requirements of the above specification not satisfied, within 15 minutes suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 40 gpm of boric acid solution at or greater than the required refueling water storage tank concentration (ppm) until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 1720 ppm, whichever is the more restrictive.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The more restrictive of the above two reactivity conditions shall be determined prior to:

a. Removing or unbolting the reactor vessel head, and

b. Withdrawal of any CEA in excess of 3 feet from its fully inserted position within the reactor pressure vessel.

4.9.1.2 The boron concentration of all filled portions of the reactor coolant system and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

4.9.1.3 Deleted

LIMITING CONDITION FOR OPERATION

3.9.2 Two source range neutron flux monitors shall be OPERABLE, each with continuous visual indication in the control room and one with audible indication in the containment, and control room.

APPLICABILITY: MODE 6.

ACTION:

a. With one of the above required monitors inoperable, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity additions.

b. With both of the above required monitors inoperable, immediately initiate action to restore one monitor to OPERABLE status. Additionally, determine that the boron concentration of the Reactor Coolant System satisfies the requirements of LCO 3.9.1 within 4 hours and at least once per 12 hours thereafter.

SURVEILLANCE REQUIREMENTS

4.9.2 Each source range neutron flux monitor shall be demonstrated OPERABLE by performance of:

a. Deleted

b. A CHANNEL CALIBRATION at least once per 18 months*

c. A CHANNEL CHECK and verification of audible counts at least once per 12 hours.

*Neutron detectors are excluded from CHANNEL CALIBRATION.

REFUELING OPERATIONS

DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.3.1 The reactor shall be subcritical for a minimum of 150 hours prior to movement of irradiated fuel in the reactor pressure vessel.

APPLICABILITY: MODE 6.

ACTION:

With the reactor subcritical for less than 150 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.

SURVEILLANCE REQUIREMENTS

4.9.3.1 The reactor shall be determined to have been subcritical for at least 150 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

LIMITING CONDITION FOR OPERATION

3.9.4 The containment penetrations shall be in the following status:

a. The equipment door shall be either:

1. closed and held in place by a minimum of four bolts, or

2. open under administrative control* and capable of being closed and held in place by a minimum of four bolts,

b. The personnel air lock shall be either:

1. closed by one personnel air lock door, or

2. capable of being closed by an OPERABLE personnel air lock door, under administrative control *, and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either:

1. Closed by a manual or automatic isolation valve, blind flange, or equivalent, or

2. Be capable of being closed under administrative control *

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving movement of irradiated fuel assemblies in the containment.

---

* Administrative controls shall ensure that appropriate personnel are aware that the equipment door, personnel air lock door and/or other containment penetrations are open, and that a specific individual(s) is designated and available to close the equipment door, personnel air lock door and/or other containment penetrations within 30 minutes if a fuel handling accident occurs. Any obstructions (e.g., cables and hoses) that could prevent closure of the equipment door, a personnel air lock door and/or other containment penetration must be capable of being quickly removed.

SURVEILLANCE REQUIREMENTS

4.9.4.1 Verify each required containment penetration is in the required status at least once per 7 days.

4.9.4.2 Deleted

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

SHUTDOWN COOLING AND COOLANT CIRCULATION - HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.1 One shutdown cooling train shall be OPERABLE and in operation.

NOTE

1. The required shutdown cooling train may not be in operation for up to 1 hour per 8 hour period provided no operations are permitted that would cause a reduction in Reactor Coolant System boron concentration.

2. The normal or emergency power source may be inoperable for the required shutdown cooling train.

3. The shutdown cooling pumps may be removed from operation during the time required for local leak rate testing of containment penetration number 10 or to permit maintenance on valves located in the common SDC suction line, provided:

    a. No operations are permitted that would cause reduction of the Reactor Coolant System boron concentration,

    b. CORE ALTERATIONS are suspended, and

    c. Containment penetrations are in the following status:

        1) The equipment door is closed and secured with at least four bolts; and

        2) At least one personnel airlock door is closed; and

        3) Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be closed with a manual or automatic isolation valve, blind flange, or equivalent.

APPLICABILITY: MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange.

REFUELING OPERATIONS

SHUTDOWN COOLING AND COOLANT CIRCULATION - HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

ACTION:

With no shutdown cooling train OPERABLE or in operation, perform the following actions:

a. Immediately suspend all operations involving a reduction in Reactor Coolant System boron concentration and the loading of irradiated fuel assemblies in the core; and

b. Immediately initiate action to restore one shutdown cooling train to OPERABLE status and operation; and

c. Within 4 hours place the containment penetrations in the following status:

    1. Close the equipment door and secure with at least four bolts; and

    2. Close at least one personnel airlock door; and

    3. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be closed with a manual or automatic isolation valve, blind flange, or equivalent.

SURVEILLANCE REQUIREMENTS

4.9.8.1 One shutdown cooling train shall be verified to be in operation and circulating reactor coolant at a flow rate greater than or equal to 1000 gpm at least once per 12 hours.

SHUTDOWN COOLING AND COOLANT CIRCULATION - LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two shutdown cooling trains shall be OPERABLE and one shutdown cooling train shall be in operation.

NOTE
The normal or emergency power source may be inoperable for each shutdown cooling train.

APPLICABILITY: MODE 6 with the water level < 23 feet above the top of the reactor vessel flange.

ACTION a. With one shutdown cooling train inoperable, immediately initiate action to restore the shutdown cooling train to OPERABLE status OR immediately initiate action to establish ≥ 23 feet of water above the top of the reactor vessel flange.

b. With no shutdown cooling train OPERABLE or in operation, perform the following actions:

1. Immediately suspend all operations involving a reduction in Reactor Coolant System boron concentration; and

2. Immediately initiate action to restore one shutdown cooling train to OPERABLE status and operation; and

3. Within 4 hours place the containment penetrations in the following status:

    a. Closed the equipment door and secure with at least four bolts; and

    b. Close at least one personnel airlock door; and

    c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be closed with a manual or automatic isolation valve, blind flange, or equivalent.

SURVEILLANCE REQUIREMENTS

4.9.8.2.1 One shutdown cooling train shall be verified to be in operation and circulating reactor coolant at a flow rate greater than or equal to 1000 gpm at least once per 12 hours.

4.9.8.2.2 The required shutdown cooling pump, if not in operation, shall be determined OPERABLE once per 7 days by verifying correct breaker alignment and indicated power available.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.11 As a minimum, 23.0 feet of water shall be maintained over the top of the reactor vessel flange.

APPLICABILITY: During CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts.

During movement of irradiated fuel assemblies within containment.

ACTION:

With the water level less than that specified above, immediately suspend CORE ALTERATIONS and immediately suspend movement of irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

4.9.11 The water level shall be determined to be within its minimum depth at least once per 24 hours.

STORAGE POOL WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.12 As a minimum, 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: WHENEVER IRRADIATED FUEL ASSEMBLIES ARE IN THE STORAGE POOL.

ACTION:

With the requirement of the specification not satisfied, suspend all movement of fuel and spent fuel pool platform crane operations with loads in the fuel storage areas.

SURVEILLANCE REQUIREMENTS

4.9.12 The water level in the storage pool shall be determined to be within its minimum depth at least once per 7 days when irradiated fuel assemblies are in the fuel storage pool.

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

SHIELDED CASK

LIMITING CONDITION FOR OPERATION

3.9.16.1 All fuel within a distance L from the center of the spent fuel pool cask laydown area shall have decayed for at least 1 year. The distance L equals the major dimension of the shielded cask.

APPLICABILITY: Whenever a shielded cask is on the refueling floor.

ACTION:

With the requirements of the above specification not satisfied, do not move a shielded cask to the refueling floor. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.16.1 The decay time of all fuel within a distance L from the center of the spent fuel pool cask laydown area shall be determined to be ≥ 1 year within 24 hours prior to moving a shielded cask to the refueling floor and at least once per 72 hours thereafter.

THIS PAGE INTENTIONALLY LEFT BLANK

SPENT FUEL POOL BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.17 The boron concentration in the spent fuel pool shall be greater than or equal to 1720 parts per million (ppm).

APPLICABILITY: Whenever any fuel assembly or consolidated fuel storage box is stored in the spent fuel pool.

ACTION:

With the boron concentration less than 1720 ppm, suspend the movement of all fuel, consolidated fuel storage boxes, and shielded casks, and immediately initiate action to restore the spent fuel pool boron concentration to within its limit.

The provisions of specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.17 Verify that the boron concentration is greater than or equal to 1720 ppm every 7 days, and within 24 hours prior to the initial movement of a fuel assembly or consolidated fuel storage box in the Spent Fuel Pool, or shielded cask over the cask laydown area.

SPENT FUEL POOL-STORAGE

LIMITING CONDITION FOR OPERATION

3.9.18 The following spent fuel pool storage requirement will be met:

(a) The combination of initial enrichment and burnup of each fuel assembly stored in Region A shall be within the acceptable burnup domain of Figure 3.9-4; and

(b)(1) The combination of initial enrichment and burnup of a fuel assembly stored in Region C shall be within the acceptable burnup domain of Figure 3.9-1A;

OR

(2) The combination of initial enrichment and burnup of a fuel assembly stored in Region C shall be within the acceptable burnup domain of Figure 3.9-1B, and borated stainless steel poison pins are installed in the assembly's center guide tube and in two diagonally opposite guide tubes; and

(c) The combination of initial enrichment and burnup of each consolidated fuel storage box stored in Region C shall be within the acceptable burnup domain of Figure 3.9-3.

APPLICABILITY: Whenever any fuel assembly or consolidated fuel storage box is stored in the spent fuel pool.

ACTION:

Immediately initiate action to move the non-complying fuel assembly or consolidated fuel storage box to an acceptable location.

The provisions of specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.18 Prior to storing a fuel assembly or consolidated fuel storage box in the spent fuel racks, verify by administrative means the initial enrichment and burnup of the fuel assembly or consolidated fuel storage box is in accordance with the acceptable specifications for that Storage Region.

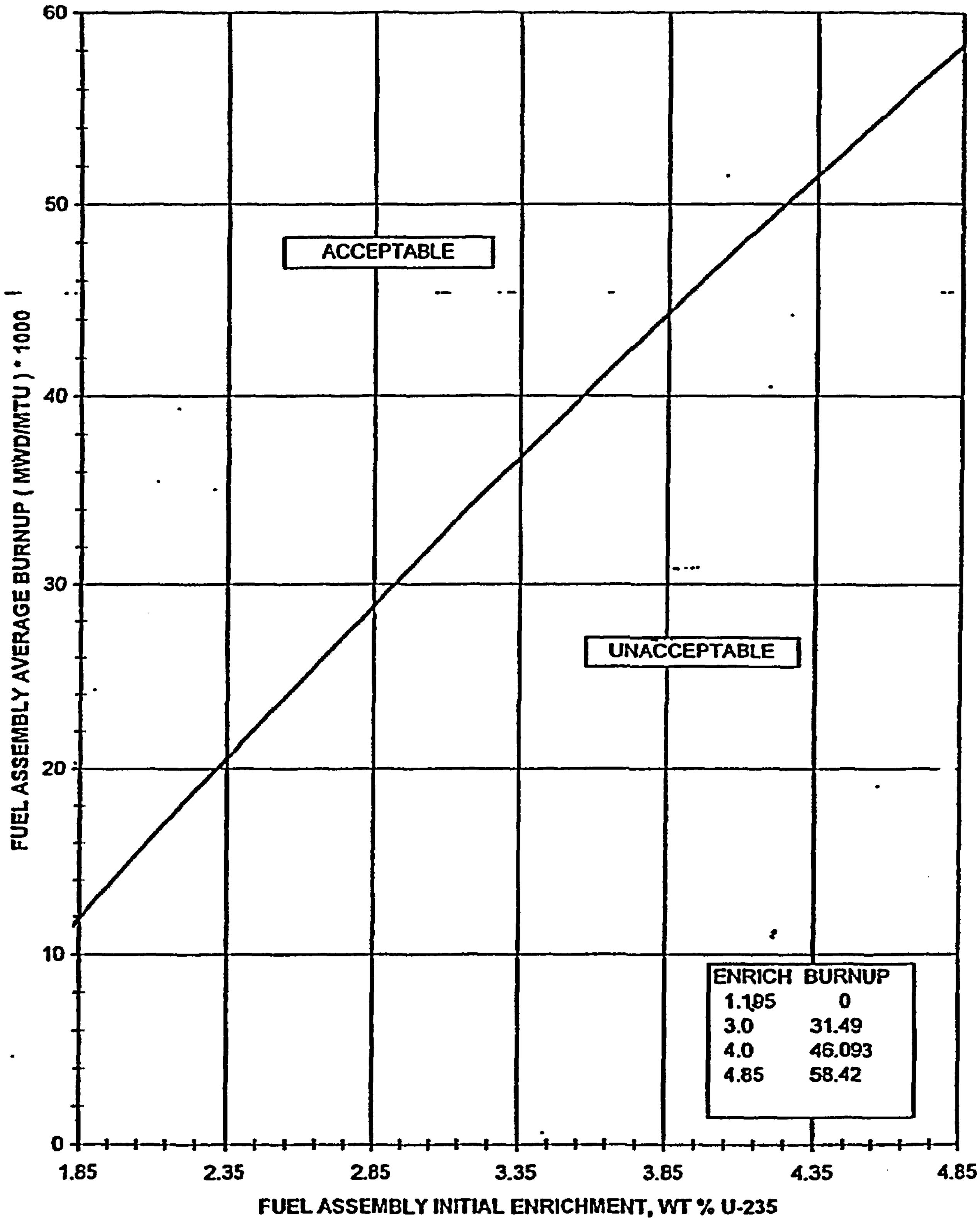


FIGURE 3.9-1A MINIMUM REQUIRED FUEL ASSEMBLY EXPOSURE AS A FUNCTION OF INITIAL ENRICHMENT TO PERMIT STORAGE IN REGION C

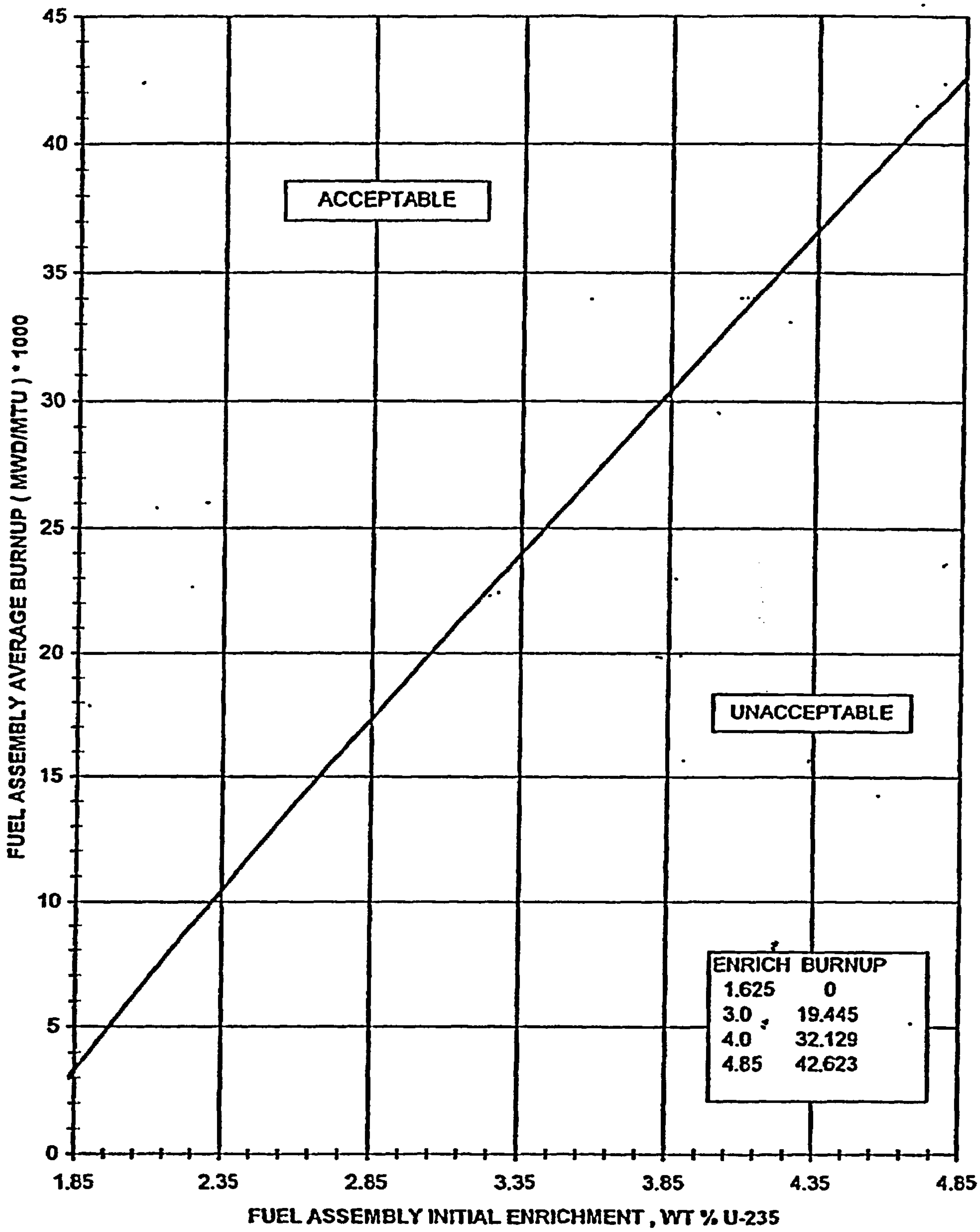
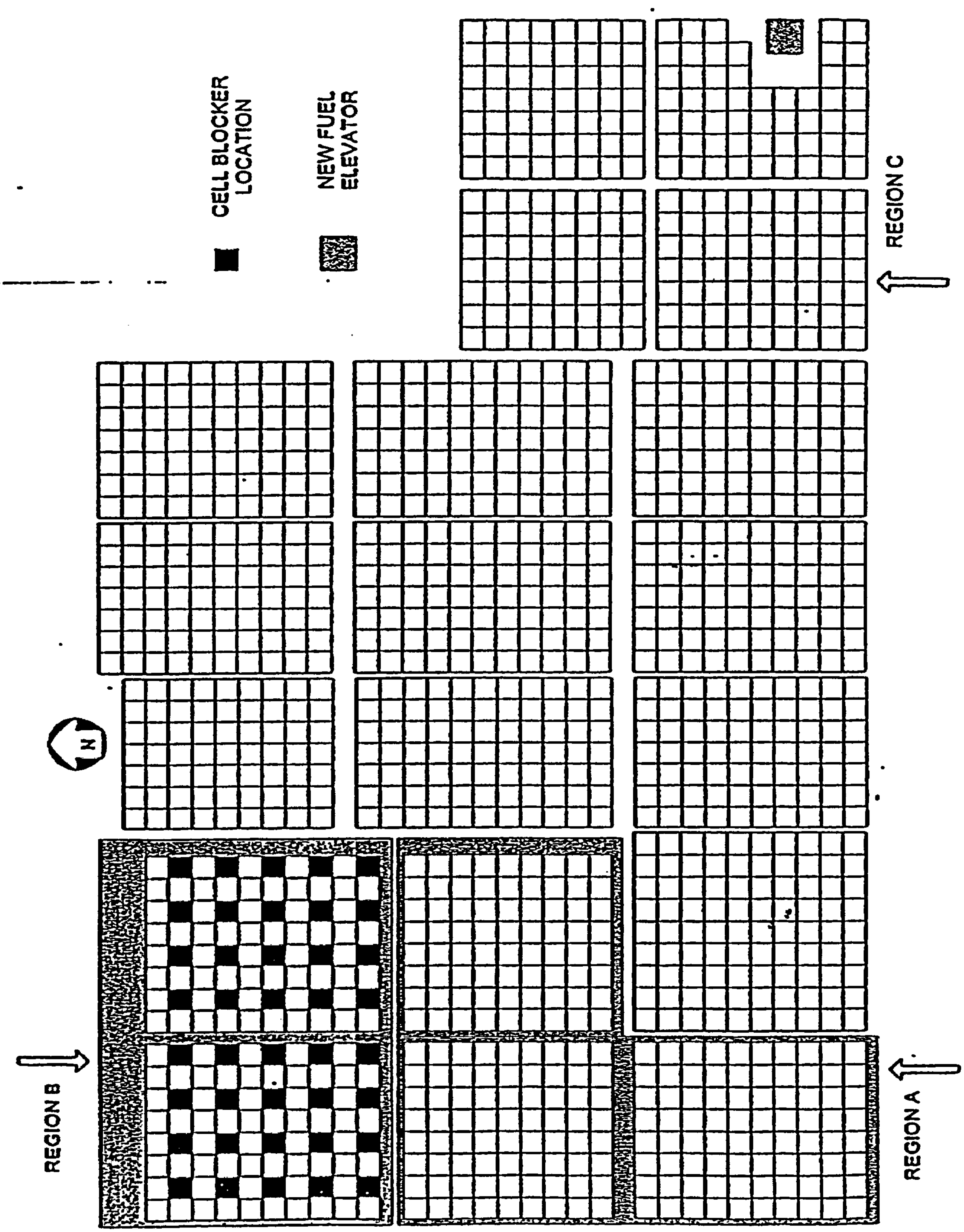


FIGURE 3.9-1B MINIMUM REQUIRED FUEL ASSEMBLY EXPOSURE AS A FUNCTION OF INITIAL ENRICHMENT TO PERMIT STORAGE IN REGION C WITH POISON PINS INSTALLED

SPENT FUEL POOL ARRANGEMENT
FIGURE 3.9-2
(NOT TO SCALE)



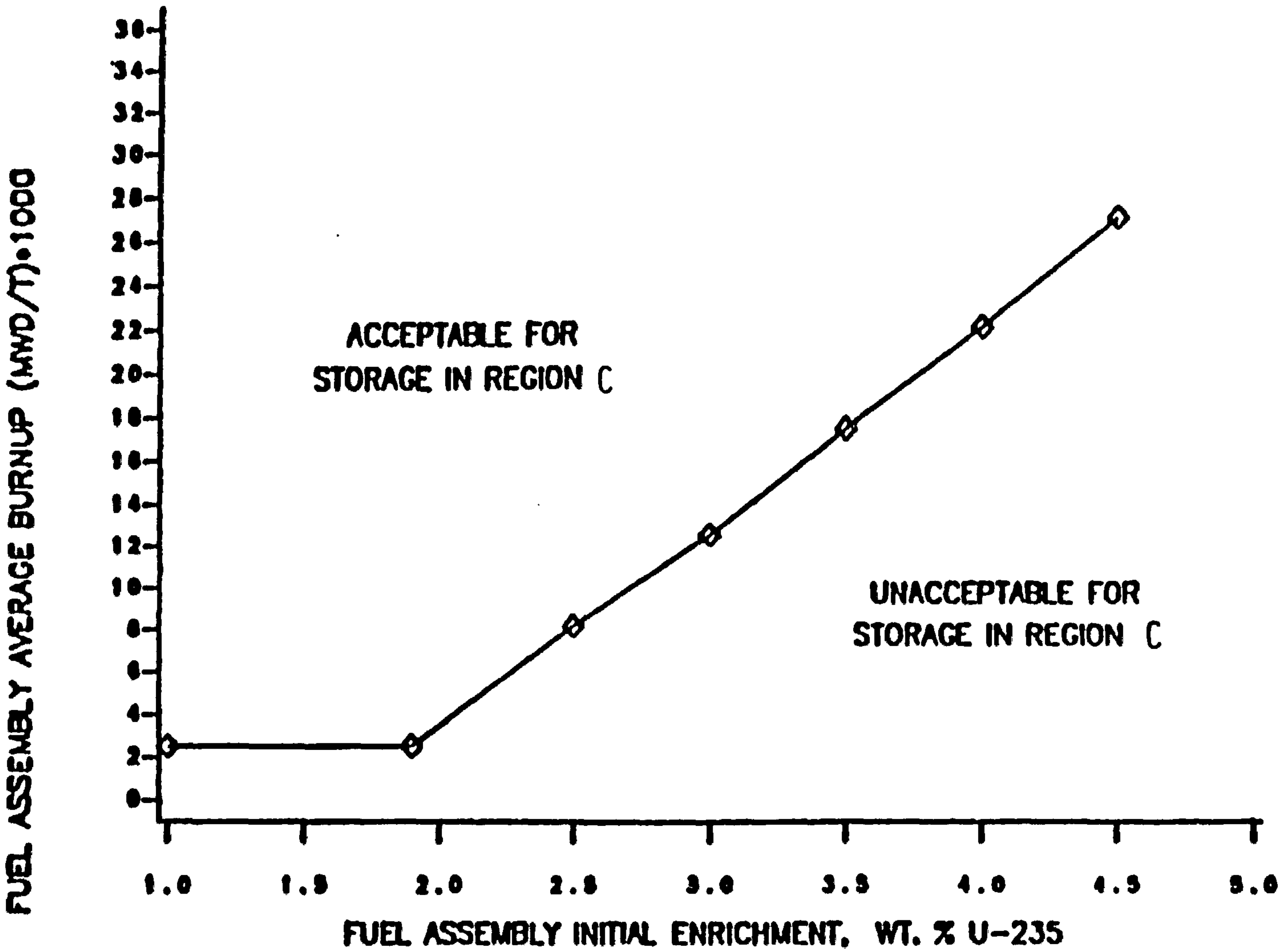


FIGURE 3.9-3 MINIMUM REQUIRED FUEL ASSEMBLY EXPOSURE AS A FUNCTION OF INITIAL ENRICHMENT TO PERMIT STORAGE IN REGION C AS CONSOLIDATED FUEL

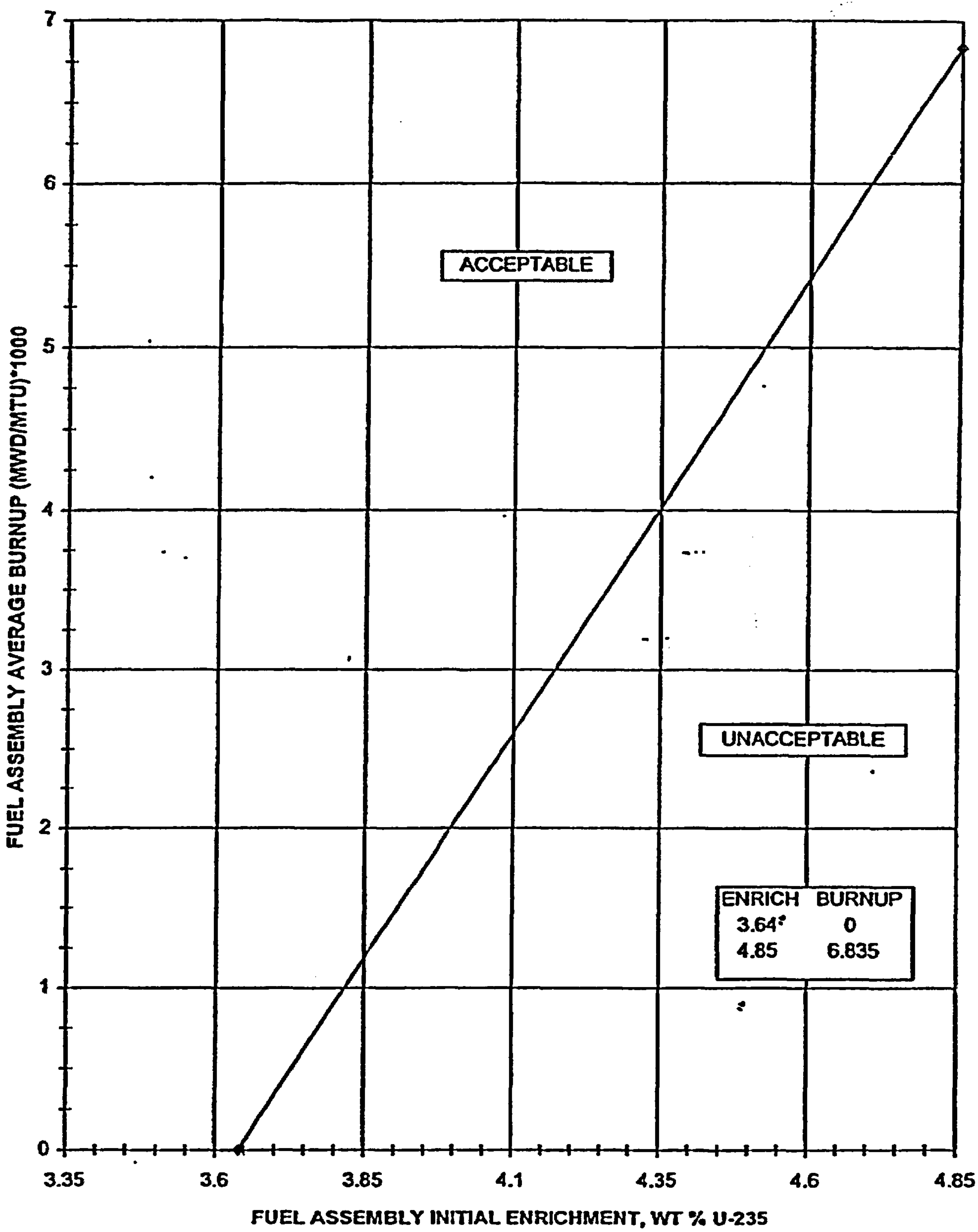


FIGURE 3.9-4 MINIMUM REQUIRED FUEL ASSEMBLY EXPOSURE AS A FUNCTION OF INITIAL ENRICHMENT TO PERMIT STORAGE IN REGION A

SPENT FUEL POOL - STORAGE PATTERN

LIMITING CONDITION FOR OPERATION

3.9.19 Each STORAGE PATTERN of the Region B spent fuel pool racks shall require that:

(1) A cell blocking device is installed in those cell locations shown in Figure 3.9-2. The blocked location may store a Batch B fuel assembly* underneath the cell blocker; or

(2) If a cell blocking device has been removed, all cells in the STORAGE PATTERN, except the location with the removed cell blocking device, must be vacant of stored fuel assemblies.

APPLICABILITY: Fuel in the spent fuel pool.**

ACTION:

Take immediate action to comply with either 3.9.19(1) or (2).

The provisions of specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.19 Verify that 3.9.19 is satisfied prior to removing a cell blocking device.

*A Batch B fuel assembly refers to any of the Batch B fuel assemblies which were part of the first Millstone 2 core.

**This LCO is not applicable during the initial installation of Batch B fuel assemblies in the cell blocker locations.

THIS PAGE INTENTIONALLY LEFT BLANK

REFUELING OPERATIONS

SPENT FUEL POOL - CONSOLIDATION

LIMITING CONDITION FOR OPERATION

3.9.20 Prior to consolidation of spent fuel assemblies, the candidate fuel assemblies must have decayed for at least 5 years.

APPLICABILITY: During all consolidation operations.

ACTION:

With the requirements of the above specification not satisfied, replace candidate assembly with an appropriate substitute or suspend all consolidation activities.

SURVEILLANCE REQUIREMENTS

4.9.20 The decay time of all candidate fuel assemblies for consolidation shall be determined to be greater than or equal to five years within 7 days prior to moving the fuel assembly into the consolidation work station.

3/4.10 SPECIAL TEST EXCEPTIONS

SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.10.1 The requirement of Specifications 3.1.1.1, 3.1.3.5 and 3.1.3.6 may be suspended for measurement of CEA worth and shutdown margin provided reactivity equivalent to at least the highest estimated CEA worth (of those CEAs actually withdrawn) is available for trip insertion from OPERABLE CEA(s).

APPLICABILITY: MODES 2 and 3[1] during PHYSICS TESTS.

ACTION:

a. With any CEA not fully inserted and with less than the above reactivity equivalent available for trip insertion, within 15 minutes initiate and continue boration at > 40 gpm of boric acid solution at or greater than the required refueling water storage tank (RWST) concentration (ppm) until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

b. With all CEAs inserted and the reactor subcritical by less than the above reactivity equivalent, immediately initiate and continue boration at > 40 gpm of boric acid solution at or greater than the required refueling water storage tank (RWST) concentration (ppm) until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

SURVEILLANCE REQUIREMENTS

4.10.1.1 The position of each CEA required either partially or fully withdrawn shall be determined at least once per 2 hours.

4.10.1.2 Each CEA not fully inserted shall be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position once within 7 days prior to reducing the SHUTDOWN MARGIN to less than the limits of Specification 3.1.1.1[2].

---

(1) Operation in MODE 3 shall be limited to 6 consecutive hours.

(2) Not required to be performed during initial power escalation following a refueling outage if SR 4.1.3.4 has been met.

SPECIAL TEST EXCEPTIONS

GROUP HEIGHT AND INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 and 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER is restricted to the test power plateau which shall not exceed 85% of RATED THERMAL POWER, and

b. The limits of Specification 3.2.1 are maintained and determined as specified in Specification 4.10.2 below.

APPLICABILITY: MODES 1 and 2.

ACTION:

With any of the limits of Specification 3.2.1 being exceeded while the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 and 3.2.4 are suspended, immediately:

a. Reduce THERMAL POWER sufficiently to satisfy the requirements of Specification 3.2.1 or

b. Be in HOT STANDBY within 2 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined at least once per hour during PHYSICS TESTS in which the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 or 3.2.4 are suspended and shall be verified to be within the test power plateau.

4.10.2.2 The linear heat rate shall be determined to be within the limits of Specification 3.2.1 by monitoring it continuously with the Incore Detector Monitoring System pursuant to the requirements of Specification 4.2.1.3 during PHYSICS TESTS above 5% of RATED THERMAL POWER in which the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 or 3.2.4 are suspended.

"This page intentionally left blank."

"This page intentionally left blank."

"This page intentionally left blank,"

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

BASES

FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

BASES

Specification 3.0.1 through 3.0.4 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10CFR50.36(c)(2):

"Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL MODES or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in a MODE or condition in which the specification no longer applies. It is not intended that the shutdown ACTION requirements be used as an operational convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

The specific time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered a MODE in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routing) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measure permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. Therefore, the shutdown may be terminated if the ACTION requirements have been met or the time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required ACTIONS.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in the COLD SHUTDOWN MODE when a shutdown is required during the POWER MODE of operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE of operation applies. However, if a lower MODE of operation is reached in less time than allowed, the total allowance time to reach COLD SHUTDOWN, or other applicable MODE, is not reduced. For example, if HOT STANDBY is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do not apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on MODE changes when a Limiting Condition for Operation is not met. It precludes placing the facility in a higher MODE of operation when the requirements for a Limiting Condition for Operation are not met and continued noncompliance to these conditions would result in a shutdown to comply with the ACTION requirements if a change in MODES were permitted. The purpose of this specification is to ensure that facility operation is not initiated or that higher MODES of operation are not entered when corrective action is being taken to obtain compliance with a specification by restoring equipment to OPERABLE status or parameters to specified limits. Compliance with ACTION requirements that permit continued operation of the facility for an unlimited period of time provides an acceptable level of safety for continued operation without regard to the status of the plant before or after a MODE change. Therefore, in this case, entry into an OPERATIONAL MODE or other specified condition may be made in accordance with the provision of the ACTION requirements. The provisions of this specification should not, however, be interpreted as endorsing the failure to exercise good practice in restoring systems or components to OPERABLE status before plant startup.

APPLICABILITY

BASES (Con't)

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 3.0.4 do not apply because they would delay placing the facility in a lower MODE of operation.

Specification 3.0.5 delineates what additional conditions must be satisfied to permit operation to continue, consistent with the ACTION statements for power sources, when a normal or emergency power source in not OPERABLE. It specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a system, subsystem, train, component or device in another division is inoperable for another reason.

The provisions of this specification permit the ACTION statements associated with individual systems, subsystems, trains, components, or devices to be consistent with the ACTION statements of the associated electrical power source. It allows operation to be governed by the time limits of the ACTION statement associated with the Limiting Condition for Operation for the normal or emergency power source, not the individual ACTION statements for each system, subsystem, train, component or device that is determined to be inoperable solely because of the inoperability of its normal emergency power source.

For example, Specification 3.8.1.1 requires in part that two emergency diesel generators be OPERABLE. The ACTION statement provides for a 72-hour out-of-service time when one emergency diesel generator is not OPERABLE. If the definition of OPERABLE were applied without consideration of Specification 3.0.5, all systems, subsystems, trains, components and devices supplied by the inoperable emergency power source would also be inoperable. This would dictate invoking the applicable ACTION statement for each of the applicable Limiting Conditions for Operation. However, the provisions of Specification 3.0.5 permit the time limits for continued operation to be consistent with the ACTION statement for the inoperable emergency diesel generator instead, provided the other specified conditions are satisfied. In this case, this would mean that the corresponding normal power source must be OPERABLE, and all redundant systems, subsystems, trains, components, and devices must be OPERABLE, or otherwise satisfy Specification 3.0.5 (i.e., be capable of performing their design function and have at least one normal or one emergency power source OPERABLE). If they are not satisfied, ACTION is required in accordance with this specification.

As a further example, Specification 3.8.1.1 requires in part that two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system be OPERABLE. The ACTION statement provides a 24-hour out-of-service time when both required offsite circuits are not OPERABLE. If the definition of OPERABLE were applied without consideration of Specification 3.0.5, all systems, subsystems, trains, components and devices supplied by the inoperable normal power sources, both of the offsite circuits, would also be inoperable. This would dictate invoking the applicable ACTION statements for each of the applicable LCOs. However, the provisions of Specification 3.0.5 permit the time limits for continued operation to

Bases Change of 6-28-2005

be consistent with the ACTION statement for the inoperable normal power sources instead, provided the other specified conditions are satisfied. In this case, this would mean that for one division the emergency power source must be OPERABLE (as must be the components supplied by the emergency power source) and all redundant systems, subsystems, trains, components and devices in the other divisions must be OPERABLE, or likewise satisfy Specification 3.0.5 (i.e., be capable of performing their design functions and have an emergency power source OPERABLE). In other words, both emergency power sources must be OPERABLE and all redundant systems, subsystems, trains, components and devices in both divisions must also be OPERABLE. If these conditions are not satisfied, ACTION is required in accordance with this specification.

In MODES 5 and 6 Specification 3.0.5 is not applicable, and thus the individual ACTION statements for each applicable Limiting Condition for Operation in these MODES must be adhered to.

Specification 3.0.6 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required ACTION(s)) to allow the performance of surveillance requirements to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed surveillance requirements. The Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of equipment being returned to service is reopening a containment isolation valve that has been closed to comply with the Required ACTIONS and must be reopened to perform the surveillance requirements.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of a surveillance requirement on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of a surveillance requirement on another channel in the same trip system.

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10CFR50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that surveillances must be met during the OPERATIONAL MODES or other conditions for which the requirements of the Limiting Conditions for Operation apply unless otherwise stated in an individual Surveillance Requirements. The purpose of this specification is to ensure that surveillances are performed to verify the OPERABILITY of systems and components and that parameters are within specified limits to ensure safe operation of the facility when the plant is in a MODE or other specified condition for which the associated Limiting Conditions for Operation are applicable. Failure to meet a Surveillance within the specified surveillance interval, in accordance with Specification 4.0.2, constitutes a failure to meet a Limiting Condition for Operation.

Systems and components are assumed to be OPERABLE when the associated Surveillance Requirements have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when either:

a. The systems or components are known to be inoperable, although still meeting the Surveillance Requirements or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillance Requirements do not have to be performed when the facility is in an OPERATIONAL MODE or other specified conditions for which the requirements of the associated Limiting Condition for Operation do not apply unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given Surveillance Requirement. In this case, the unplanned event may be credited as fulfilling the performance of the Surveillance Requirement. This allowance includes those Surveillance Requirements whose performance is normally precluded in a given MODE or other specified condition.

Surveillance Requirements, including Surveillances invoked by ACTION requirements, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with Specification 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Auxiliary feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressure > 800 psi. However, if other appropriate testing is satisfactorily completed, the AFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

b. High pressure safety injection (HPSI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPSI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 This specification establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified surveillance interval. A delay period of up to 24 hours or up to the limit of the specified surveillance interval, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified surveillance interval was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with ACTION requirements or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance. with a surveillance interval based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations, (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified surveillance interval to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

Specification 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by ACTION requirements. |

Failure to comply with specified surveillance intervals for the Surveillance Requirements is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified surveillance interval is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the entry into the ACTION requirements for the applicable Limiting Condition for Operation begins immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and entry into the ACTION requirements for the applicable Limiting Condition for Operation begins immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Allowed Outage Time of the applicable ACTIONS, restores compliance with Specification 4.0.1.

Specification 4.0.4 establishes the requirement that all applicable surveillances must be met before entry into an OPERATIONAL MODE or other condition of operation specified in the Applicability statement. The purpose of this specification is to ensure that system and component OPERABILITY requirements or parameter limits are met before entry into a MODE or condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in OPERATIONAL MODES or other specified conditions associated with plant shutdown as well as startup.

Under the provisions of this specification, the applicable Surveillance Requirements must be performed within the specified surveillance interval to ensure that the Limiting Conditions for Operation are met during initial plant startup or following a plant outage.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 4.0.4 do not apply because this would delay placing the facility in a lower MODE of operation.

Specification 4.0.5 establishes the requirement 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 shall 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 50.55a. These requirements apply except when relief has been provided in writing by the Commission.

This specification includes a clarification of the frequencies for 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 the 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. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL MODE or other specified condition takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, that is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code 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 REACTIVITY CONTROL SYSTEMS

3/4.1.1.1 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.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, the minimum SHUTDOWN MARGIN specified in the CORE OPERATING LIMITS REPORT is initially required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN required by Specification 3.1.1.1 is based upon this limiting condition and is consistent with FSAR accident analysis assumptions. For earlier periods during the fuel cycle, this value is conservative. The SHUTDOWN MARGIN is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;
b. CEA positions;
c. RCS average temperature;
d. Fuel burnup based on gross thermal energy generation;
e. Xenon concentration;
f. Samarium concentration; and
g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical and the fuel temperature will be changing at the same rate as the RCS temperature.

3/4.1.1.2 REACTIVITY BALANCE

Reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control element assembly (CEA) worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SHUTDOWN MARGIN (SDM) or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RATED THERMAL POWER following startup from a refueling outage, with the CEAs in their normal positions for power operation. The normalization is performed at BOC conditions, so that core

3/4.1.1 REACTIVITY CONTROL SYSTEMS (Continued)

3/4.1.1.2 REACTIVITY BALANCE (Continued)

reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

When measured core reactivity is within ±1% Δk/k of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits.

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. This Specification does not apply in MODES 3 , 4 and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 1000 GPM provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during reductions in Reactor Coolant System boron concentration. The 1000 GPM limit is the minimum required shutdown cooling flow to satisfy the boron dilution accident analysis. This 1000 GPM flow is an analytical limit. Plant operating procedures maintain the minimum shutdown cooling flow at a higher value to accommodate flow measurement uncertainties. While the plant is operating in reduced inventory operations, plant operating procedures also specify an upper flow limit to prevent vortexing in the shutdown cooling system. A flow rate of at least 1000 GPM will circulate the full Reactor Coolant System volume in approximately 90 minutes. With the RCS in mid-loop operation, the Reactor Coolant System volume will circulate in approximately 25 minutes. The reactivity change rate associated with reductions in Reactor Coolant System boron concentration will be within the capability for operator recognition and control.

A maximum of two charging pumps capable of injecting into the RCS when RCS cold leg temperature is < 300°F ensures that the maximum inadvertent dilution flow rate assumed in the boron dilution analysis is not exceeded.

3/4.1.1.3 BORON DILUTION (Continued)

A charging pump can be considered to be not capable of injecting into the RCS by use of any of the following methods and the appropriate administrative controls.

1. Placing the motor circuit breaker in the open position.

2. Removing the charging pump motor overload heaters from the charging pump circuit.

3. Removing the charging pump motor controller from the motor control center.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the assumptions used in the accident and transient analyses remain valid through each fuel cycle. The surveillance requirements for measurement of the MTC during each fuel cycle are adequate to confirm the MTC value since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup. The confirmation that the measured MTC value is within its limit provides assurance that the coefficient will be maintained within acceptable values throughout each fuel cycle.

3/4.1.1.5 MINIMUM TEMPERATURE FOR CRITICALITY

The MTC is expected to be slightly negative at operating conditions. However, at the beginning of the fuel cycle, the MTC may be slightly positive at operating conditions and since it will become more positive at lower temperatures, this specification is provided to restrict reactor operation when T_{avg} is significantly below the normal operating temperature.

3/4.1.2 DELETED

3/4.1.3 MOVEABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) the potential effects of a CEA ejection accident are limited to acceptable levels.

The ACTION statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original criteria are met.

Page B 3/4 1-3 has been removed from Tech Specs as a result of this LBDCR

Page B 3/4 1-3a has been removed from Tech Specs as a result of this LBDCR

3/4.1.3 MOVEABLE CONTROL ASSEMBLIES (Continued)

A CEA may become misaligned, yet remain trippable. In this condition, the CEA can still perform its required function of adding negative reactivity should a reactor trip be necessary. If one or more CEAs (regulating or shutdown) are misaligned by > 10 steps and < 20 steps but trippable, or one CEA is misaligned by ≥ 20 steps but trippable, continued operation in MODES 1 and 2 may continue, provided, within 1 hour, the power is reduced to < 70% RATED THERMAL POWER, and within 2 hours CEA alignment is restored. If negative reactivity insertion is required to reduce THERMAL POWER, boration shall be used. Regulating CEA alignment can be restored by either aligning the misaligned CEA(s) to within 10 steps of all other CEAs in its group or aligning the misaligned CEA's group to within 10 steps of the misaligned CEA. A Regulating CEA is considered fully inserted when either the Dropped Rod indication or lower Electrical Limit indication lights on the core mimic display are illuminated. A Regulating CEA is considered to be fully withdrawn when withdrawn ≥ 176 steps. Shutdown CEA alignment can only be restored by aligning the misaligned CEA(s) to within 10 steps of its group.

Xenon redistribution in the core starts to occur as soon as a CEA becomes misaligned. Reducing THERMAL POWER ensures acceptable power distributions are maintained. For small misalignments (< 20 steps) of the CEAs, there is:

a. A small effect on the time dependent long term power distributions relative to those used in generating LCOs and limiting safety system settings (LSSS) setpoints;

b. A negligible effect on the available SHUTDOWN MARGIN; and

c. A small effect on the ejected CEA worth used in the accident analysis.

With a large CEA misalignment (≥ 20 steps), however, this misalignment would cause distortion of the core power distribution. This distortion may, in turn, have a significant effect on the time dependent, long term power distributions relative to those used in generating LCOs and LSSS setpoints. The effect on the available SHUTDOWN MARGIN and the ejected CEA worth used in the accident analysis remain small. Therefore, this condition is limited to a single CEA misalignment, while still allowing 2 hours for recovery.

In both cases, a 2 hour time period is sufficient to:

a. Identify cause of a misaligned CEA;

b. Take appropriate corrective action to realign the CEAs; and

c. Minimize the effects of xenon redistribution.

If a CEA is untrippable, it is not available for reactivity insertion during a reactor trip. With an untrippable CEA, meeting the insertion limits of LCO 3.1.3.5 and LCO 3.1.3.6 does not ensure that adequate SHUTDOWN MARGIN exists. With one or more CEAs untrippable the plant is transitioned to MODE 3 within 6 hours.

3/4.1.3 MOVEABLE CONTROL ASSEMBLIES (Continued)

The CEA motion inhibit permits CEA motion within the requirements of LCO 3.1.3.6, "Regulating Control Element Assembly (CEA) Insertion Limits," and the CEA deviation circuit prevents regulating CEAs from being misaligned from other CEAs in the group. With the CEA motion inhibit inoperable, a time of 6 hours is allowed for restoring the CEA motion inhibit to OPERABLE status, or placing and maintaining the CEA drive switch in either the "off" or "manual" position, fully withdrawing all CEAs in group 7 to < 5% insertion. Placing the CEA drive switch in the "off" or "manual" position ensures the CEAs will not move in response to Reactor Regulating System automatic motion commands. Withdrawal of the CEAs to the positions required in the Required ACTION B.2 ensures that core perturbations in local burnup, perking factors, and SHUTDOWN MARGIN will not be more adverse than the Conditions assumed in the safety analyses and LCO setpoint determination. Required ACTION B.2 is modified by a Note indicating that performing this Required ACTION is not required when in conflict with Required ACTIONS A.1 or C.1.

Continued operation is not allowed in the case of more than one CEA misaligned from any other CEA in its group by ≥ 20 steps, or one or more CEAs untrippable. This is because these cases are indicative of a loss of SHUTDOWN MARGIN and power distribution changes, and a loss of safety function, respectively.

OPERABILITY of the CEA position indicators (Specification 3.1.3.3) is required to determine CEA positions and thereby ensure compliance with the CEA alignment and insertion limits and ensures proper operation of the CEA Motion Inhibit and CEA deviation block circuit. The CEA "Full In" and "Full Out" limit Position Indicator channels provide an additional independent means for determining the CEA positions when the CEAs are at either their fully inserted or fully withdrawn positions. Therefore, the ACTION statements applicable to inoperable CEA position indicators permit continued operations when the positions of CEAs with inoperable position indicators can be verified by the "Full In" or "Full Out" limit Position Indicator channels.

CEA positions and OPERABILITY of the CEA position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCO's are satisfied.

The maximum CEA drop time permitted by Specification 3.1.3.4 is the assumed CEA drop time used in the accident analyses. Measurement with $T_{avg} \geq 515°F$ and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES (Continued)

The LSSS setpoints and the power distribution LCOs were generated based upon a core burnup which would be achieved with the core operating in an essentially unrodded configuration. Therefore, the CEA insertion limit specifications require that during MODES 1 and 2, the CEAs be nearly fully withdrawn. The amount of CEA insertion permitted by the Long Term Steady State Insertion Limits of Specification 3.1.3.6 will not have a significant effect upon the unrodded burnup assumption but will still provide sufficient reactivity control. The Transient Insertion Limits of Specification 3.1.3.6 are provided to ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) the potential effects of a CEA ejection accident are limited to acceptable levels; however, long term operation at these insertion limits could have adverse effects on core power distribution during subsequent operation in an unrodded configuration. The PDIL alarm, CEA Motion Inhibit and CEA deviation circuit are provided by the CEAPDS computer.

The control rod drive mechanism requirement of specification 3.1.3.7 is provided to assure that the consequences of an uncontrolled CEA withdrawal from subcritical transient will stay within acceptable levels. This specification assures that reactor coolant system conditions exist which are consistent with the plant safety analysis prior to energizing the control rod drive mechanisms. The accident is precluded when conditions exist which are inconsistent with the safety analysis since deenergized drive mechanisms cannot withdraw a CEA. The drive mechanisms may be energized with the boron concentration greater than or equal to the refueling concentration since, under these conditions, adequate SHUTDOWN MARGIN is maintained, even if all CEAs are fully withdrawn from the core.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

3/4.2.1 LINEAR HEAT RATE

The limitation on linear heat rate ensures that in the event of a LOCA, the peak temperature of the fuel cladding will not exceed 2200°F.

Either of the two core power distribution monitoring systems, the Excore Detector Monitoring System and the Incore Detector Monitoring System, provide adequate monitoring of the core power distribution and are capable of verifying that the linear heat rate does not exceed its limits. The Excore Detector Monitoring System performs this function by continuously monitoring the AXIAL SHAPE INDEX with two OPERABLE excore neutron flux detectors and verifying that the AXIAL SHAPE INDEX is maintained within the allowable limits specified in the CORE OPERATING LIMITS REPORT using the Power Ratio Recorder. The power dependent limits of the Power Ratio Recorder are less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT. In conjunction with the use of the excore monitoring system and in establishing the AXIAL SHAPE INDEX limits, the following assumptions are made: 1) the CEA insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are satisfied, 2) the AZIMUTHAL POWER TILT restrictions of Specification 3.2.4 are satisfied, and 3) the TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTOR does not exceed the limits of Specification 3.2.3.

The Incore Detector Monitoring System continuously provides a direct measure of the peaking factors and the alarms which have been established for the individual incore detector segments ensure that the peak linear heat rates will be maintained within the allowable limits specified in the CORE OPERATING LIMITS REPORT. The setpoints for these alarms include allowances, set in the conservative direction. The Incore Detector Monitoring System is not used to monitor linear heat rate below 20% of RATED THERMAL POWER. The accuracy of the neutron flux information from the incore detectors is not reliable at THERMAL POWER < 20% RATED THERMAL POWER.

3/4.2.3 AND 3/4.2.4 TOTAL UNRODDED INTEGRATED RADIAL PEAKING FACTORS F^T_r AND AZIMUTHAL POWER TILT - T_q

The limitations on F^T_r and T_q are provided to 1) ensure that the assumptions used in the analysis for establishing the Linear Heat Rate and Local power Density - High LCOs and LSSS setpoints remain valid during operation at the various allowable CEA group insertion limits, and, 2) ensure that the assumptions used in the analysis establishing the DNB Margin LCO, and Thermal Margin/Low Pressure LSSS setpoints remain valid during operation at the various allowable CEA group insertion limits. If F^T_r or T_q exceed their basic limitations, operation may continue under the additional restrictions imposed

Bases Change of 6-28-2005

by the ACTION statements since these additional restrictions provide adequate provisions to assure that the assumptions used in establishing the Linear Heat Rate, Thermal Margin/Low Pressure and Local Power Density - High LCOs and LSSS setpoints remain valid. An AZIMUTHAL POWER TILT > 0.10 is not expected and if it should occur, subsequent operation would be restricted to only those operations required to identify the cause of this unexpected tilt.

Core power distribution is a concern any time the reactor is critical. The Total Integrated Radial Peaking Factor - F^T_r LCO, however, is only applicable in MODE 1 above 20% of RATED THERMAL POWER. The reasons that this LCO is not applicable below 20% of RATED THERMAL POWER are:

a. Data from the incore detectors are used for determining the measured radial peaking factors. Technical Specification 3.2.3 is not applicable below 20% of RATED THERMAL POWER because the accuracy of the neutron flux information from the incore detectors is not reliable at THERMAL POWER < 20% RATED THERMAL POWER.

b. When core power is below 20% of RATED THERMAL POWER, the core is operating well below its thermal limits, and the Local Power Density (fuel pellet melting) and Thermal Margin/Low Pressure (DNB) trips are highly conservative.

The surveillance requirements for verifying that F^T_r and T_q are within their limits provide assurance that the actual values of F^T_r and T_q do not exceed the assumed values. Verifying F^T_r after each fuel loading prior to exceeding 70% of RATED THERMAL POWER provides additional assurance that the core was properly loaded.

3/4.2.6 DNB MARGIN

The limitations provided in this specification ensure that the assumed margins to DNB are maintained. The limiting values of the parameters in this specification are those assumed as the initial conditions in the accident and transient analyses; therefore, operation must be maintained within the specified limits for the accident and transient analyses to remain valid.

3/4.3.1 AND 3/4.3.2 PROTECTIVE AND ENGINEERED SAFETY FEATURES (ESF) INSTRUMENTATION

The OPERABILITY of the protective and ESF instrumentation systems and bypasses ensure that 1) the associated ESF action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic is maintained, 3) sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance, and 4) sufficient system functional capability is available for protective and ESF purposes from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundance and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses.

ACTION Statement 2 of Tables 3.3-1 and 3.3-3 requires an inoperable Reactor Protection System (RPS) or Engineered Safety Feature Actuation System (ESFAS) channel to be placed in the bypassed or tripped condition within 1 hour. The inoperable channel may remain in the bypassed condition for a maximum of 48 hours. While in the bypassed condition, the affected functional unit trip coincidence will be 2 out of 3. After 48 hours, the channel must either be declared OPERABLE, or placed in the tripped condition. If the channel is placed in the tripped condition, the affected functional unit trip coincidence will become 1 out of 3. One additional channel may be removed from service for up to 48 hours, provided one of the inoperable channels is placed in the tripped condition.

Plant operation with an inoperable pressurizer high pressure reactor protection channel in the tripped condition is restricted because of the potential inadvertent opening of both pressurizer power operated relief valves (PORVs) if a second pressurizer high pressure reactor protection channel failed while the first channel was in the tripped condition. This plant operating restriction is contained in the Technical Requirements Manual.

The reactor trip switchgear consists of eight reactor trip circuit breakers, which are operated in four sets of two breakers (four channels). Each of the four trip legs consists of two reactor trip circuit breakers in series. The two reactor trip circuit breakers within a trip leg are actuated by separate initiation circuits. For example, if a breaker receives an open signal in trip leg A, an identical breaker in trip leg B will also receive an open signal. This arrangement ensures that power is interrupted to both Control Element Drive Mechanism buses, thus preventing a trip of only half of the control element assemblies (a half trip). Any one inoperable breaker in a channel will make the entire channel inoperable.

The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability.

The surveillance testing verifies OPERABILITY of the RPS by overlap testing of the four interconnected modules: measurement channels, bistable trip units, RPS logic, and reactor trip circuit breakers. When testing the measurement channels or bistable trip units that provide an automatic reactor trip function, the associated RPS channel will be removed from service,

Bases Change of 6-28-2005

3/4.3.1 AND 3/4.3.2 PROTECTIVE AND ENGINEERED SAFETY FEATURES (ESF) INSTRUMENTATION (continued)

declared inoperable, and ACTION Statement 2 of Technical Specification 3.3.1.1 entered. When testing the RPS logic (matrix testing), the individual RPS channels will not be affected. Each parameter within each RPS channel supplies three contacts to make up the 6 different logic ladders/ matrices (AB, AC, AD, BC, BD, and CD). During matrix testing, only one logic matrix is tested at a time. Since each RPS channel supplies 3 different logic ladders, testing one ladder matrix at a time will not remove an RPS channel from the overall logic matrix. Therefore, matrix testing will not remove an RPS channel from service or make the RPS channel inoperable. It is not necessary to enter an ACTION statement while performing matrix testing. This also applies when testing the reactor trip circuit breakers since this test will not remove an RPS channel from service or make the RPS channel inoperable.

The ESFAS includes four sensor subsystems and two actuation subsystems for each of the functional units identified in Table 3.3-3. Each sensor subsystem includes measurement channels and bistable trip units. Each of the four sensor subsystem channels monitors redundant and independent process measurement channels. Each sensor is monitored by at least one bistable. The bistable associated with each ESFAS Function will trip when the monitored variable exceeds the trip setpoint. When tripped, the sensor subsystems provide outputs to the two actuation subsystems.

The two independent actuation subsystems each compare the four associated sensor subsystem outputs. If a trip occurs in two or more sensor subsystem channels, the two-out-of-four automatic actuation logic will initiate one train of ESFAS. An Automatic Test Inserter (ATI), for which the automatic actuation logic OPERABILITY requirements of this specification do not apply, provides automatic test capability for both the sensor subsystems and the actuation subsystems.

The provisions of Specification 4.0.4 are not applicable for the CHANNEL FUNCTIONAL TEST of the Engineered Safety Feature Actuation System automatic actuation logic associated with Pressurizer Pressure Safety Injection, Pressurizer Pressure Containment Isolation, Steam Generator Pressure Main Steam Line Isolation, and Pressurizer Pressure Enclosure Building Filtration for entry into MODE 3 or other specified conditions. After entering MODE 3, pressurizer pressure and steam generator pressure will be increased and the blocks of the ESF actuations on low pressurizer pressure and low steam generator pressure will be automatically removed. After the blocks have been removed, the CHANNEL FUNCTIONAL TEST of the ESF automatic actuation logic can be performed. The CHANNEL FUNCTIONAL TEST of the ESF automatic actuation logic must be performed within 12 hours after establishing the appropriate plant conditions, and prior to entry into MODE 2.

The measurement of response time at the specified frequencies provides assurance that the protective and ESF action function associated with each channel is completed within the time limit assumed in the accident analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable. The Reactor Protective and Engineered Safety Feature response times are contained in the Millstone Unit No. 2 Technical Requirements Manual. Changes to the Technical Requirements Manual require a 10CFR50.59 review as well as a review by the Plant Operations Review Committee.

3/4.3.1 AND 3/4.3.2 PROTECTIVE AND ENGINEERED SAFETY FEATURES (ESF) INSTRUMENTATION (Continued)

SRAS LOGIC MODIFICATION

ACTION Statement 4 of Table 3.3-3, which applies only to the SRAS logic, specifies that during surveillance testing the second inoperable channel must also be placed in the bypassed condition. For the SRAS logic, placing the second inoperable channel in the tripped condition (as in ACTION Statement 2) could result in the false generation of a SRAS signal due to an additional failure which causes a trip signal in either of the remaining channels at the onset of a LOCA. The false generation of the SRAS signal leads to unacceptable consequences for LOCA mitigation.

With ACTION Statement 4, during the two-hour period when two channels are bypassed, no additional failure can result in the false generation of the SRAS signal. However, an additional failure that prevents a trip of either of the two remaining channels may prevent the generation of a true SRAS signal while in this ACTION Statement. If no SRAS is generated at the appropriate time, operating procedures instruct the operator to ensure that the SRAS actuation occurs when the refueling water storage tank level decreases. Due to the limited period of vulnerability, and the existence of operator requirements to manually initiate an SRAS if an automatic initiation does not occur, this risk is considered acceptable.

STEAM GENERATOR BLOWDOWN ISOLATION

Automatic isolation of steam generator blowdown will occur on low steam generator water level. An auxiliary feedwater actuation signal will also be generated at this steam generator water level. Isolation of steam generator blowdown will conserve steam generator water inventory following a loss of main feedwater.

SENSOR CABINET POWER SUPPLY AUCTIONEERING

The auctioneering circuit of the ESFAS sensor cabinets ensures that two sensor cabinets do not de-energize upon loss of a D.C. bus, thereby resulting in the false generation of an SRAS. Power source VA-10 provides normal power to sensor cabinet A and backup power to sensor cabinet D. VA-40 provides normal power to sensor cabinet D and backup power to cabinet A. Power sources VA-20 and VA-30 and sensor cabinets B and C are similarly arranged.

If the normal or backup power source for an ESFAS Sensor Cabinet is lost, two sensor cabinets would be supplied from the same power source, but would still be operating with no subsequent trip signals present. However, any additional failure associated with this power source would result in the loss of the two sensor cabinets, consequently generating a false SRAS. The 48-hour ACTION Statement ensures that the probability of a ACTION Statement and an additional failure of the remaining power source, while in this ACTION Statement is sufficiently small.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring channels ensures that 1) the radiation levels are continually measured in the areas served by the individual channels and 2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded.

The analysis for a Steam Generator Tube Rupture Event and for a Millstone Unit No. 3 Loss of Coolant Accident credits the control room ventilation inlet duct radiation monitors with closure of the Unit 2 control room isolation dampers. In the event of a single failure in either channel (1 per train), the control room isolation dampers automatically close. The response time test for the control room isolation dampers includes signal generation time and damper closure. The response time for the control room isolation dampers is maintained within the applicable facility surveillance procedure.

The containment airborne radiation monitors (gaseous and particulate) provide early indication of leakage from the Reactor Coolant System as specified in Technical Specification 3.4.6.1.

3/4.3.3.2 - DELETED

3/4.3.3.3 - DELETED

3/4.3.3.4 - DELETED

3/4.3.3.5 REMOTE SHUTDOWN INSTRUMENTATION

The OPERABILITY of the remote shutdown instrumentation ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the facility 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.

3/4.3.3.6 DELETED

3/4.3.3.7 DELETED

3/4.3.3.8 Accident Monitoring Instrumentation

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and 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".

This page intentionally left blank

3/4.3.3.9 - DELETED

3/4.3.3.10 - DELETED

3/4.3.4 Containment Purge Valve Isolation Signal

A high airborne radioactivity level inside containment will be detected by the containment airborne radiation monitors (gaseous and particulate). The actuation logic for this function is one out of four. High radioactivity inside containment, detected by any one of the four radiation detectors (two gaseous and two particulate), will automatically isolate containment PURGE.

An OPERABLE system consists of at least one gaseous and particulate radiation detector and the associated automatic logic train. An actuation logic train consists of the detectors, associated microprocessors, and the associated logic circuits up to and including the Engineered Safeguards Actuation System system actuation module.

These radiation monitors provide an automatic closure signal to the containment purge valves upon detection of high airborne radioactivity levels inside containment. The maximum allowable trip value for these monitors corresponds to calculated concentrations at the site boundary which would not exceed the concentrations listed in 10 CFR Part 20, Appendix B, Table II. Exposure for a year to the concentrations in 10 CFR Part 20, Appendix B, Table II, corresponds to a total body dose to an individual of 500 mrem, which is well below the guidelines of 10 CFR Part 100 for an individual at any point on the exclusion area boundary for two hours.

Determination of the monitor's trip value in counts per minute, which is the actual instrument response, involves several factors including: 1) the atmospheric dispersion (x/Q), 2) isotopic composition of the sample, 3) sample flow rate, 4) sample collection efficiency, 5) counting efficiency, and 6) the background radiation level at the detector. The x/Q of 5.8 x 10-6 sec/m3 is the highest annual average x/Q estimated for the site boundary (0.48 miles in the NE sector) for vent releases from the containment and 7.5 x 10-8 sec/m3 is the highest annual average x/Q estimated for an off-site location (3 miles in the NNE sector) for releases from the Unit 1 stack. This calculation also assumes that the isotopic composition is xenon-133 for gaseous radioactivity and cesium-137 for particulate radioactivity (Half Lives greater than 8 days). The upper limit of 5 x 105 cpm is approximately 90 percent of full instrument scale.

3/4.4.1 COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with both Reactor Coolant System (RCS) loops and associated reactor coolant pumps (RCPs) in operation, and maintain the DNBR above the 95/95 limit for the DNB correlation during all normal operations and anticipated transients. In MODES 1 and 2, both RCS loops and associated RCPs are required to be OPERABLE and in operation.

In MODE 3, a single RCS loop with one RCP and adequate steam generator secondary water inventory provides sufficient heat removal capability. However, both RCS loops with at least one RCP per loop are required to be OPERABLE to provide redundant paths for decay heat removal. In addition, as a minimum, one RCS loop must be in operation. Any exceptions to these requirements are contained in the LCO Notes.

In MODE 4, one RCS loop with one RCP and adequate steam generator secondary water inventory, or one shutdown cooling (SDC) train provides sufficient heat removal capability. However, two loops or trains, consisting of any combination of RCS loops or SDC trains, are required to be OPERABLE to provide redundant paths for decay heat removal. In addition, as a minimum, one RCS loop or SDC train must be in operation. Any exceptions to these requirements are contained in the LCO Notes.

In MODES 3 and 4, an OPERABLE RCS loop consists of the RCS loop, associated steam generator, and at least one RCP. The steam generator must have sufficient secondary water inventory for heat removal.

In MODE 5, with the RCS loops filled, the SDC trains are the primary means of heat removal. One SDC train provides sufficient heat removal capability. However, to provide redundant paths for decay heat removal either two SDC trains are required to be OPERABLE, or one SDC train is required to be OPERABLE and both steam generators are required to have adequate steam generator secondary water inventory. In addition, as a minimum, one SDC train must be in operation. Any exceptions to these requirements are contained in the LCO Notes.

By maintaining adequate secondary water inventory and makeup capability, the steam generators will be able to support natural circulation in the RCS loops. In addition, the ability to pressurize and control RCS pressure is necessary to support RCS natural circulation. If the pressurizer steam bubble has been collapsed and the RCS has been depressurized or drained sufficiently that voiding of the steam generator U-tubes may have occurred, the RCS loops should be considered not filled unless an evaluation is performed to verify the ability of the RCS to support natural circulation. If the RCS loops are considered not filled, the RCS must be refilled, pressurized, and the RCPs bumped (unless a vacuum fill of the RCS was performed) before the RCS loops can be considered filled.

In MODE 5, with the RCS loops not filled, the SDC trains are the only means of heat removal. One SDC train provides sufficient heat removal capability. However, to provide redundant paths for decay heat removal, two SDC trains are required to be OPERABLE. In addition, as a minimum, one SDC

Revised by NRC letter dated May 1, 2002.
Bases Change

3/4.4.1 COOLANT LOOPS AND COOLANT CIRCULATION (continued)

train must be in operation. Any exceptions to these requirements are contained in the LCO Notes.

An OPERABLE SDC train, for plant operation in MODES 4 and 5, includes a pump, heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine RCS temperature. In addition, sufficient portions of the Reactor Building Closed Cooling Water (RBCCW) and Service Water (SW) Systems shall be OPERABLE as required to provide cooling to the SDC heat exchanger. The flow path starts at the RCS hot leg and is returned to the RCS cold legs.

In MODE 4, an OPERABLE SDC train consists of the following equipment:

1. An OPERABLE SDC pump (low pressure safety injection pump);

2. The associated SDC heat exchanger from the same facility as the SDC pump;

3. The associated reactor building closed cooling water loop from the same facility as the SDC pump;

4. The associated service water loop from the same facility as the SDC pump; and

5. All valves required to support SDC System operation are in the required position or are capable of being placed in the required position.

In MODE 4, two OPERABLE SDC trains require 2 SDC pumps, 2 SDC heat exchangers, 2 RBCCW pumps, 2 RBCCW heat exchangers, and 2 SW pumps. In addition, 2 RBCCW headers and 2 SW headers are required to support the SDC heat exchangers, consistent with the requirements of Technical Specifications 3.7.3.1 and 3.7.4.1.

In MODE 5, an OPERABLE SDC train consists of the following equipment:

1. An OPERABLE SDC pump (low pressure safety injection pump);

2. The associated SDC heat exchanger from the same facility as the SDC pump;

3. An RBCCW pump, powered from the same facility as the SDC pump, and RBCCW heat exchanger capable of cooling the associated SDC heat exchanger;

4. A SW pump, powered from the same facility as the SDC pump, capable of supplying cooling water to the associated RBCCW heat exchanger; and

5. All valves required to support SDC System operation are in the required position or are capable of being placed in the required position.

3/4.4.1 COOLANT LOOPS AND COOLANT CIRCULATION (continued)

In MODE 5, two OPERABLE SDC trains require 2 SDC pumps, 2 SDC heat exchangers, 2 RBCCW pumps, 2 RBCCW heat exchangers, and 2 SW pumps. In addition, 2 RBCCW headers are required to provide cooling to the SDC heat exchangers, but only 1 SW header is required to support the SDC trains. The equipment specified is sufficient to address a single active failure of the SDC System and associated support systems.

The operation of one Reactor Coolant Pump or one shutdown cooling pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump in MODE 4 with one or more RCS cold legs ≤ 275°F and in MODE 5 are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by:

1. Restricting pressurizer water volume to ensure sufficient steam volume is available to accommodate the insurge;

2. Restricting pressurizer pressure to establish an initial pressure that will ensure system pressure does not exceed the limit; and

3. Restricting primary to secondary system delta-T to reduce the energy addition from the secondary system.

If these restrictions are met, the steam bubble in the pressurizer is sufficient to ensure the Appendix G limits will not be exceeded. No credit has been taken for PORV actuation to limit RCS pressure in the analysis of the energy addition transient.

The limitations on pressurizer water level, pressurizer pressure, and primary to secondary delta-T are necessary to ensure the validity of the analysis of the energy addition due to starting an RCP. The values for pressurizer water level and pressure can be obtained from control room indications. The primary to secondary system delta-T can be obtained from Shutdown Cooling (SDC) System outlet temperature and the saturation temperature for indicated steam generator pressure. If there is no indicated steam generator pressure, the steam generator shell temperature indicators can be used. If these indications are not available, other appropriate instrumentation can be used.

The RCP starting criteria values for pressurizer water level, pressurizer pressure, and primary to secondary delta-T contained in Technical Specifications 3.4.1.3, 3.4.1.4 and 3.4.1.5 have not been adjusted for instrument uncertainty. The values for these parameters contained in the procedures that will be used to start an RCP have been adjusted to compensate for instrument uncertainty.

Bases Change of 6-28-2005

3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.1 COOLANT LOOPS AND COOLANT CIRCULATION (continued)

The value of RCS cold leg temperature ($\leq$ 275°F) used to determine if the RCP start criteria applies, will be obtained from SDC return temperature if SDC is in service. If SDC is not in service, or natural circulation is occurring, RCS cold leg temperature will be used.

Average Coolant Temperature (T_{avg}) values are derived under the following 3 plant conditions, using the designated formula as appropriate for use in Unit 2 operating procedures.

- RCP Operation: $(T_{cold1} + T_{cold2} + T_{hot1} + T_{hot2}) / 4 = T_{avg}$
- Natural circulation only flow: $(T_{cold1} + T_{cold2} + T_{hot1} + T_{hot2}) / 4 = T_{avg}$
- SDC flow greater than 1000 gpm: $(SDC_{outlet} + SDC_{inlet}) / 2 = T_{avg}$
  (exception: T_{avg} is not expected to be calculated by this definition during the initial portion of the initiation phase of SDC. The transition point from loop temperature average to SDC system average during cooldowns is when T351Y decreases below Loop T_{cold})

During operation with one or more Reactor Coolant Pumps (RCPs) providing forced flow and during natural circulation conditions, the loop Resistance Temperature Detectors (RTDs) represent the inlet and outlet temperatures of the reactor and hence the average temperature of the water that the reactor is exposed to. This holds during concurrent RCP/SDC operation also.

During Shutdown Cooling (SDC) only operation, there is no significant flow past the loop RTDs. Core inlet and outlet temperatures are accurately measured during those conditions by using T351Y, SDC return to RCS temperature indication, and T351X, RCS to SDC temperature indication. The average of these two indicators provides a temperature that is equivalent to the average RCS temperature in the core.

During the transition from Steam Generator (SG) and SDC heat removal to SDC only heat removal, actual core average temperature results from a mixture of both SDC flow and loop flow from natural circulation. This condition occurs from the time SDC cooling is initiated until SG steaming process stops removing heat. The temperature of this mixture cannot be measured or calculated. However, the average of the SDC temperatures is still appropriate for use. This provides a straightforward process for determining T_{avg}.

3/4.4 REACTOR COOLANT SYSTEM

BASES

3/4.4.1 COOLANT LOOPS AND COOLANT CIRCULATION (continued)

During some transient conditions, such as heatups on SDC, the value calculated by this average definition will be slightly higher than the actual core average. During other transients, such as cooldowns where SG heat removal is still taking place causing some natural circulation flow, the value calculated by the average definition will be slightly lower than actual core average conditions. For the purpose of determining MODE changes and technical specification applicability, these transient condition results are conservative.

Technical Specification 3.4.1.6 limits the number of reactor coolant pumps that may be operational during MODE 5. This will limit the pressure drop across the core when the pumps are operated during low-temperature conditions. Controlling the pressure drop across the core will maintain maximum RCS pressure within the maximum allowable pressure as calculated in Code Case No. N-514. Limiting two reactor coolant pumps to operate when the RCS cold leg temperature is less than 120° F, will ensure that the requirements of 10 CFR 50 Appendix G are not exceeded. Surveillance 4.4.1.6 supports this requirement.

3/4.4.2 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2750 psia. Each safety valve is designed to relieve 296,000 lbs per hour of saturated steam at the valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. If any pressurizer code safety valve is inoperable, and cannot be restored to OPERABLE status, the ACTION statement requires the plant to be shut down and cooled down such that Technical Specification 3.4.9.3 will become applicable and require the Low Temperature Overpressure Protection System to be placed in service to provide overpressure protection.

Bases Change of 6-28-2005

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2750 psia. The combined relief capacity of these valves is sufficient to limit the Reactor Coolant System pressure to within its Safety Limit of 2750 psia following a complete loss of turbine generator load while operating at RATED THERMAL POWER and assuming no reactor trip until the first Reactor Protective System trip setpoint (Pressurizer Pressure-High) is reached (i.e., no credit is taken for a direct reactor trip on the loss of turbine) and also assuming no operation of the pressurizer power operated relief valve or steam dump valves.

3/4.4.3 RELIEF VALVES

The power operated relief valves (PORVs) operate to relieve RCS pressure below the setting of the pressurizer code safety valves. These relief valves have remotely operated block valves to provide a positive shutoff capability should a relief valve become inoperable. The electrical power for both the relief valves and the block valves is capable of being supplied from an emergency power source to ensure the ability to seal this possible RCS leakage path.

The PORVs are also used for low temperature overpressure protection when the RCS is cooled down to or below 275°F. This is covered by Technical Specification 3.4.9.3 and discussed in the respective Bases section. The discussion below only addresses the PORVs in MODES 1, 2 and 3.

With the PORV inoperable and capable of being manually cycled, either the PORV must be restored, or the flow path isolated within 1 hour. The block valve should be closed, but the power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. Although the PORV may be designated inoperable, it may be able to be manually opened and closed and in this manner can be used to perform its function. PORV inoperability may be due to seat leakage, instrumentation problems, automatic control problems, or other causes that do not prevent manual use and do not create a possibility for a small break LOCA. Operation of the plant may continue with the PORV in this inoperable condition for a limited period of time not to exceed the next refueling outage, so that maintenance can be performed on the PORVs to eliminate the degraded condition. The PORVs should normally be available for automatic mitigation of overpressure events when the plant is at power.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve.

If one block valve is inoperable, then it must be restored to OPERABLE status, or the associated PORV prevented from opening automatically. The prime importance for the capability to maintain closed the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the required ACTION is to prevent the associated PORV from automatically opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. This may be accomplished by various methods. These methods include, but are not limited to, placing the NORMAL/ISOLATE switch at the associated Bottle Up Panel in the "ISOLATE" position or pulling the control power fuses for the associated PORV control circuit.

Although the block valve may be designated inoperable, it may be able to be manually opened and closed and in this manner can be used to perform its function. Block valve inoperability may be due to seat leakage, instrumentation problems, or other causes that do not prevent manual use and do not create a possibility for a small break LOCA. This condition is only intended to permit operation of the plant for a limited period of time. The block valve should normally be available to allow PORV operation for automatic mitigation of overpressure events. The block valves must be returned to OPERABLE status prior to entering MODE 3 after a refueling outage.

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the completion time of 1 hour or isolate the flow path by closing and removing the power to the associated block valve and cooldown the RCS to MODE 4.

3/4.4.4 PRESSURIZER

An OPERABLE pressurizer provides pressure control for the reactor coolant system during operations with both forced reactor coolant flow and with natural circulation flow. The minimum water level in the pressurizer assures the pressurizer heaters, which are required to achieve and maintain pressure control, remain covered with water to prevent failure, which occurs if the heaters are energized uncovered. The maximum water level in the pressurizer ensures that this parameter is maintained within the envelope of operation assumed in the safety analysis. The maximum water level also ensures that the RCS is not a hydraulically solid system and that a steam bubble will be provided to accommodate pressure surges during operation. The steam bubble also protects the pressurizer code safety valves and power operated relief valve against water relief. The requirement that a minimum number of pressurizer heaters be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish and maintain natural circulation.

The requirement for two groups of pressurizer heaters, each having a capacity of 130 kW, is met by verifying the capacity of the pressurizer proportional heater groups 1 and 2. Since the pressurizer proportional heater groups 1 and 2 are supplied from the emergency 480V electrical buses, there is reasonable assurance that these heaters can be energized during a loss of offsite power to maintain natural circulation at HOT STANDBY.

3/4.4.5 STEAM GENERATORS

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking.

The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 0.035 GPM, per steam generator). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 0.035 gallon per minute can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging or sleeving will be required for all tubes with imperfections exceeding the plugging limit of 40% of the tube nominal wall thickness. Sleeving repair will be limited to those steam generator tubes with a defect between the tube sheet and the first eggcrate support. Tubes containing sleeves with imperfections exceeding the plugging limit will be plugged. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission pursuant to 10 CFR 50.72. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

Bases Change of 6-28-2005

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 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 detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems."

3/4.4.6.2 REACTOR COOLANT SYSTEM LEAKAGE

Industry experience has shown that while a limited amount of leakage is expected from the RCS, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 GPM. This threshold value is sufficiently low to ensure early detection of additional leakage.

The 10 GPM IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the leakage detection systems.

The steam generator tube leakage limit of 0.035 GPM per steam generator ensures that the dosage contribution from the tube leakage will be less than the limits of General Design Criteria 19 of 10CFR50 Appendix A in the event of either a steam generator tube rupture or steam line break. The 0.035 GPM limit is consistent with the assumptions used in the analysis of these accidents.

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

The IDENTIFIED LEAKAGE and UNIDENTIFIED LEAKAGE limits listed in LCO 3.4.6.2 only apply to the reactor coolant system pressure boundary within the containment.

In accordance with 10 CFR 50.2 "Definitions" the RCS Pressure Boundary means all those pressure-containing components such as pressure vessels, piping, pumps and valves which are (1) Part of the Reactor Coolant System, or (2) Connected to the Reactor Coolant System, up to and including any and all of the following: (i) The outermost containment isolation valve in system piping which penetrates primary reactor containment, (ii) The second of two valves normally closed in system piping which does not penetrate primary reactor containment, or (iii) The reactor coolant safety and relief valves.

The definitions for IDENTIFIED LEAKAGE and UNIDENTIFIED LEAKAGE are provided in the Technical Specifications definitions section, definitions 1.14 and 1.15 respectively.

Leakage outside of the second isolation valve for containment which is included in the RCS Leak Rate Calculation is not considered RCS leakage and can be subtracted from RCS UNIDENTIFIED LEAKAGE.

The safety significance of RCS leakage varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS leakage into the containment area is necessary. Quickly separating IDENTIFIED LEAKAGE from the UNIDENTIFIED LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur. LCO 3.4.6.2 deals with protection of the reactor coolant pressure boundary from degradation and the core from inadequate cooling, in addition accident analysis radiation release assumptions from being exceeded.

3/4.4.7 DELETE

3/4.4.8 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the resulting 2 hour doses at the SITE BOUNDARY will not exceed an appropriately small fraction of Part 100 limits following a steam generator tube rupture accident.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity > 1.0 uCi/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER.

Reducing T_{avg} to < 515°F prevents the release of activity should a steam generator tube rupture since the saturation pressure of the primary coolant is below the lift pressure of the atmospheric steam relief valves. The surveillance requirements provide adequate assurance that excessive specific activity levels in the primary coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with iodine spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 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 4.0 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. In addition, during heatup and cooldown evolutions, the RCS ferritic materials transition between ductile and brittle (non-ductile) behavior. To provide adequate protection, the pressure/temperature limits were developed in accordance with the 10CFR50 Appendix G requirements to ensure the margins of safety against non-ductile failure are maintained during all normal and anticipated operational occurrences. These pressure/temperature limits are provided in Figures 3.4-2a and 3.4-2b and the heatup and cooldown rates are contained in Table 3.4-2.

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 thermally induced compressive stresses at the inside wall 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 at the outer wall of the vessel. These stresses are additive to the pressure induced tensile stresses which are already present. The thermally 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 heatup and cooldown limit curves (Figures 3.4-2a and 3.4-2b) are composite curves which were prepared by determining the most conservative case, with either the inside or outside wall controlling, for any heatup or cooldown rates of up to the maximums described in Technical Specification 3.4.9.1, Table 3.4-2. The heatup and cooldown curves were prepared based upon the most limiting value of the predicted adjusted reference temperature at the end of the service period indicated on Figures 3.4-2a and 3.4-2b.

Verification that RCS pressure and temperature conditions are within the limits of Figures 3.4-2a and 3.4-2b and Table 3.4-2, at least once per 30 minutes, is required when undergoing planned changes of ≥ 10°F or ≥ 100 psi. This frequency is considered reasonable since the location of interest during cooldown is over two inches (i.e. 1/4 t location) from the interface with the reactor coolant. During heatup the location of interest is over six inches from the interface with the reactor coolant. This combined with the relatively large heat retention capability of the reactor vessel ensures that small temperature fluctuations such as those expected during normal heatup and cooldown evolutions do not challenge the structural integrity of the reactor vessel when monitored on a 30 minute frequency. The 30 minute time interval permits assessment and correction for minor deviations within a reasonable time.

During RCS heatup and cooldown the magnitude of the stresses across the reactor vessel wall are controlled by restricting the rate of temperature change and the system pressure. The RCS pressure/temperature limits are provided in Figures 3.4-2a and 3.4-2b, and the heatup and cooldown rates are contained in Table 3.4-2. The following guidelines should be used to ensure compliance with the Technical Specification limits.

1. When changing RCS temperature, with any reactor coolant pumps in operation, the rate of temperature change is calculated by using RCS loop cold leg temperature indications.

   This also applies during parallel reactor coolant pump and shutdown cooling (SDC) pump operation because the RCS loop cold leg temperature is the best indication of the temperature of the fluid in contact with the reactor vessel wall. Even though SDC return temperature may be below RCS cold leg temperature, the mixing of a large quantity of RCS cold leg water and a small quantity of SDC return water will result in the temperature of the water reaching the reactor vessel wall being very close to RCS cold leg temperature.

2. When changing RCS temperature via natural circulation, the rate of temperature change is calculated by using RCS loop cold leg temperature indications.

3. When changing RCS temperature with only SDC in service, the rate of temperature change is calculated by using SDC return temperature indication.

4. During the transition from natural circulation flow, to forced flow with SDC pumps, the rate of temperature change is calculated by using RCS loop cold leg temperature indications. SDC return temperature should be used to calculate the rate of temperature change after SDC is in service, RBCCW flow has been established to the SDC heat exchanger(s), and SDC return temperature has decreased below RCS cold leg temperature.

5. During the transition from parallel reactor coolant pump and SDC pump operation, the rate of temperature change is calculated by using RCS loop cold leg temperature indications until all reactor coolant pumps are secured. SDC return temperature should be used to calculate the rate of temperature change after all reactor coolant pumps have been secured.

6. The temperature change limits are for a continuous one hour period. Verification of operation within the limit must compare the current RCS water temperature to the value that existed one hour before the current time. If the maximum temperature increase or decrease, during this one hour period, exceeds the Technical Specification limit, appropriate action should be taken.

7. When a new, more restrictive temperature change limit is approached, it will be necessary to adjust the current temperature change rate such that as soon as the new rate applies, the total temperature change for the previous one hour does not exceed the new more restrictive rate.

   The same principle applies when moving from one temperature change limit curve to another. If the new curve is above the current curve (higher RCS pressure for a given RCS temperature), the new curve will reduce the temperature change limit. It will be necessary to first ensure the new more restrictive temperature change limit will not be exceeded by looking at the total RCS temperature change for the previous one hour time period. If the magnitude of the previous one hour temperature change will exceed the new limit, RCS temperature should be stabilized to allow the thermal stresses to dissipate. This may require up to a one hour soak before RCS pressure may be raised within the limits of the new curve.

   If the new curve is below the current curve (lower RCS pressure for a given RCS temperature), the new curve will allow a higher temperature change limit. All that is necessary is to lower RCS pressure, and then apply the new higher temperature change limit.

8. When performing evolutions that may result in rapid and significant temperature swings (e.g. placing SDC in service or shifting SDC heat exchangers), the total temperature change limit for the previous one hour period must not be exceeded. If a significant temperature change is anticipated, and an RCS heatup or cooldown is in progress, the plant should be stabilized for up to one hour, before performing this type of evolution. Stabilizing the plant for up to one hour will allow the thermal stresses, from any previous RCS temperature change, to dissipate. This will allow rapid RCS temperature changes up to the applicable Technical Specification temperature change limit.

9. Additional margin, to prevent exceeding the Appendix G limits when RCS temperature is at or below 230°F, can be obtained by maintaining RCS pressure below the pressure allowed by the 50°F/hr cooldown curve provided on Figure 3.4-2b. This will ensure that if a greater than anticipated temperature excursion occurs during short duration evolutions, the margins of safety required by Appendix G will not be exceeded. Examples of plant evolutions that may result in unanticipated temperature excursions include placing SDC in service without parallel RCP operation, securing RCPs when SDC is already in service, shifting SDC heat exchangers, and switching SDC pumps. Establishing a lower RCS pressure, will minimize the probability of exceeding Appendix G limits.

   If the 50°F/hr cooldown curve is used to evaluate unanticipated temperature excursions while limited to a cooldown rate of 30°F/hr, the RCS cooldown rate must be restored to within the 30°F/hr limit as soon as practical. This may require a soak period to allow the thermal stresses, from the previous RCS temperature change, to dissipate.

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Table 4.6-1 of the Final Safety Analysis Report. Reactor operation and resultant fast neutron irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, can be predicted using the methods described in Revision 2 to Regulatory Guide 1.99.

The heatup and cooldown limit curves shown on Figures 3.4-2a and 3.4-2b include predicted adjustments for this shift in RT_{NDT} at the end of the applicable service period, as well as adjustments for possible uncertainties in the pressure and temperature sensing instruments. The adjustments include the pressure and temperature instrument and loop uncertainties associated with the main control board displays, the pressure drop across the core (RCP operation), and the elevation differences between the location of the pressure transmitters and the vessel beltline region. In addition to these curve adjustments, the LTOP evaluation includes adjustments due to valve stroke times, PORV circuitry reaction times, and valve discharge backpressure.

The actual shift in RT_{NDT} of the vessel material is established periodically during operation by removing and evaluating, in accordance with 10CFR50 Appendix H, reactor vessel material irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and vessel inside radius are similar, the measured transition shift for a sample can be correlated to the adjacent section of the reactor vessel. The heatup and cooldown curves must be recalculated when the ΔRT_{NDT} determined from the surveillance capsule exceeds the calculated ΔRT_{NDT} for the equivalent capsule radiation exposure.

The pressure-temperature limit lines shown on Figures 3.4-2a and 3.4-2b 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 50 for reactor criticality and for inservice leak and hydrostatic testing.

The maximum RT_{NDT} for all reactor coolant system pressure-retaining materials, with the exception of the reactor pressure vessel, has been determined to be 50°F. The Lowest Service Temperature limit is based upon this RT_{NDT} since Article NB-2332 (Summer Addenda of 1972) of Section III of the ASME Boiler and Pressure Vessel Code requires the Lowest Service Temperature to be RT_{NDT} + 100°F for piping, pumps and valves. Below this temperature, the system pressure must be limited to a maximum of 20% of the system's hydrostatic test pressure of 3125 psia. Operation of the RCS within the limits of the heatup and cooldown curves will ensure compliance with this requirement.

Included in this evaluation is consideration of flange protection in accordance with 10 CFR 50, Appendix G. The requirement makes the minimum temperature RT_{NDT} plus 90°F for hydrostatic test and RT_{NDT} plus 120°F for normal operation when the pressure exceeds 20 percent of the preservice system hydrostatic test pressure. Since the flange region RT_{NDT} has been calculated to be 30°F, the minimum flange pressurization temperature during normal operation is 150°F (161°F with instrument uncertainty) when the pressure exceeds 20% of the preservice hydrostatic pressure. Operation of the RCS within the limits of the heatup and cooldown curves will ensure compliance with this requirement.

To establish the minimum boltup temperature, ASME Code Section XI, Appendix G, requires the temperature of the flange and adjacent shell and head regions shall be above the limiting RT_{NDT} temperature for the most limiting material of these regions. The RT_{NDT} temperature for that material is 30°F. Adding 10.5°F, for temperature measurement uncertainty, results in a minimum boltup temperature of 40.5°F. For additional conservatism, a minimum boltup temperature of 70°F is specified on the heatup and cooldown curves. The head and vessel flange region temperature must be greater than 70°F, whenever any reactor vessel stud is tensioned.

The Low Temperature Overpressure Protection (LTOP) System provides a physical barrier against exceeding the 10CFR50 Appendix G pressure/temperature limits during low temperature RCS operation either with a steam bubble in the pressurizer or during water solid conditions. This system consists of either two PORVs (each PORV is equivalent to a vent of approximately 1.4 square inches) with a pressure setpoint ≤ 415 psia, or an RCS vent of sufficient size. Analysis has confirmed that the design basis mass addition transient discussed below will be mitigated by operation of the PORVs or by establishing an RCS vent of sufficient size.

The LTOP System is required to be OPERABLE when RCS cold leg temperature is at or below 275°F (Technical Specification 3.4.9.3). However, if the RCS is in MODE 6 and the reactor vessel head has been removed, a vent of sufficient size has been established such that RCS pressurization is not possible. Therefore, an LTOP System is not required (Technical Specification 3.4.9.3 is not applicable).

The LTOP System is armed at a temperature which exceeds the limiting 1/4t RT_{NDT} plus 90°F as required by NUREG-0800 (i.e., SRP), Branch Technical Position RSB 5-2. For the operating period up to 20 EFPY, the limiting 1/4t RT_{NDT} is 145°F which results in a minimum LTOP System enable temperature of at least 263°F when corrected for instrument uncertainty. The current value of 275°F will be retained.

The mass input analysis performed to ensure the LTOP System is capable of protecting the reactor vessel assumes that all pumps capable of injecting into the RCS start, and then one PORV fails to actuate (single active failure). Since the PORVs have limited relief capability, certain administrative restrictions have been implemented to ensure that the mass input transient will not exceed the relief capacity of a PORV. The analysis has determined two PORVs (assuming one PORV fails) are sufficient if the mass addition transient is limited to the inadvertent start of one high pressure safety injection (HPSI) pump and two charging pumps when RCS temperature is at or below 275°F and above 190°F, and the inadvertent start of one charging pump when RCS temperature is at or below 190°F.

The assumed active failure of one PORV results in an equivalent RCS vent size of approximately 1.4 square inches when the one remaining PORV opens. Therefore, a passive vent of at least 1.4 square inches can be substituted for the PORVs. However, a vent size of at least 2.2 square inches will be required when VENTING the RCS. If the RCS is depressurized and vented through at least a 2.2 square inch vent, the peak RCS pressure, resulting from the maximum mass input transient allowed by Technical Specification 3.4.9.3, will not exceed 300 psig (SDC System suction side design pressure).

When the RCS is at or below 190°F, additional pumping capacity can be made capable of injecting into the RCS by establishing an RCS vent of at least 2.2 square inches. Removing a pressurizer PORV or the pressurizer manway will result in a passive vent of at least 2.2 square inches. Additional methods to establish the required RCS vent are acceptable, provided the proposed vent has been evaluated to ensure the flow characteristics are equivalent to one of these.

Establishing a pressurizer steam bubble of sufficient size will be sufficient to protect the reactor vessel from the energy addition transient associated with the start of an RCP, provided the restrictions contained in Technical Specification 3.4.1.3 are met. These restrictions limit the heat

Bases Change of 6-28-2005

input from the secondary system. They also ensure sufficient steam volume exists in the pressurizer to accommodate the insurge. No credit for PORV actuation was assumed in the LTOP analysis of the energy addition transient.

The restrictions apply only to the start of the first RCP. Once at least one RCP is running, equilibrium is achieved between the primary and secondary temperatures, eliminating any significant energy addition associated with the start of the second RCP.

The LTOP restrictions are based on RCS cold leg temperature. This temperature will be determined by using RCS cold leg temperature indication when RCPs are running, or natural circulation if it is occurring. Otherwise, SDC return temperature indication will be used.

Restrictions on RCS makeup pumping capacity are included in Technical Specification 3.4.9.3. These restrictions are based on balancing the requirements for LTOP and shutdown risk. For shutdown risk reduction, it is desirable to have maximum makeup capacity and to maintain the RCS full (not vented). However, for LTOP it is desirable to minimize makeup capacity and vent the RCS. To satisfy these competing requirements, makeup pumps can be made not capable of injecting, but available at short notice.

A charging pump can be considered to be not capable of injecting into the RCS by use of any of the following methods and the appropriate administrative controls.

1. Placing the motor circuit breaker in the open position.

2. Removing the charging pump motor overload heaters from the charging pump circuit.

3. Removing the charging pump motor controller from the motor control center.

A HPSI pump can be considered to be not capable of injecting into the RCS by use of any of the following methods and the appropriate administrative controls.

1. Racking down the motor circuit breaker from the power supply circuit.

2. Shutting and tagging the discharge valve with the key lock on the control panel (2-SI-654 or 2-SI-656).

3. Placing the pump control switch in the pull-to-lock position and removing the breaker control power fuses.

4. Placing the pump control switch in the pull-to-lock position and shutting the discharge valve with the key lock on the control panel (2-SI-654 or 2-SI-656).

These methods to prevent charging pumps and HPSI pumps from injecting into the RCS, when combined with the appropriate administrative controls, meet the requirement for two independent means to prevent pump injection as a result of a single failure or inadvertent single action.

These methods prevent inadvertent pump injections while allowing manual actions to rapidly restore the makeup capability if conditions require the use of additional charging or HPSI pumps for makeup in the event of a loss of RCS inventory or reduction in SHUTDOWN MARGIN.

If a loss of RCS inventory or reduction in SHUTDOWN MARGIN event occurs, the appropriate response will be to correct the situation by starting RCS makeup pumps. If the loss of inventory or SHUTDOWN MARGIN is significant, this may necessitate the use of additional RCS makeup pumps that are being maintained not capable of injecting into the RCS in accordance with Technical Specification 3.4.9.3. The use of these additional pumps to restore RCS inventory or SHUTDOWN MARGIN will require entry into the associated ACTION statement. The ACTION statement requires immediate action to comply with the specification. The restoration of RCS inventory or SHUTDOWN MARGIN can be considered to be part of the immediate action to restore the additional RCS makeup pumps to a not capable of injecting status. While recovering RCS inventory or SHUTDOWN MARGIN, RCS pressure will be maintained below the Appendix G limits. After RCS inventory or SHUTDOWN MARGIN has been restored, the additional pumps should be immediately made not capable of injecting and the ACTION statement exited.

An exception to Technical Specification 3.0.4 is specified for Technical Specification 3.4.9.3 to allow a plant cooldown to MODE 5 if one or both PORVs are inoperable. MODE 5 conditions may be necessary to repair the PORV(s).

3/4.4.10 DELETED

3/4.4.11 DELETED

3/4.5.1 SAFETY INJECTION TANKS

The OPERABILITY of each of the RCS SITs ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the SITs. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

The limits on SIT volume, boron concentration and pressure ensure that the assumptions used for SIT injection in the accident analysis are met.

If the boron concentration of one SIT is not within limits, it must be returned to within the limits within 72 hours. In this condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced, but the reduced concentration effects on core subcriticality during reflood are minor. Boiling of the ECCS water in the core during reflood concentrates the boron in the saturated liquid that remains in the core. In addition, the volume of the SIT is still available for injection. Since the boron requirements are based on the average boron concentration of the total volume of three SITs, the consequences are less severe than they would be if a SIT were not available for injection. Thus, 72 hours is allowed to return the boron concentration to within limits.

If one SIT is inoperable, for a reason other than boron concentration or the inoperability of water level or pressure channel instrumentation, the SIT must be returned to OPERABLE status within 24 hours. In this condition, the required contents of three SITs cannot be assumed to reach the core during a LOCA as is assumed in Appendix K to 10CFR50.

Reference 1 provides a series of deterministic and probabilistic analysis findings that support 24 hours as being either "risk beneficial" or "risk neutral" in comparison to shorter periods for restoring the SIT to OPERABLE status. Reference 1 discusses recent best-estimate analysis that confirmed that for large-break LOCAs, core melt can be prevented by either operation of one LPSI pump or the operation of one HPSI pump and a single SIT. Reference 1 also discusses plant-specific probabilistic analysis that evaluated the risk-impact of the 24 hour recovery period in comparison to shorter recovery periods.

If the SIT cannot be restored to OPERABLE status within the associated completion time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3

Reference

1 CE NPSD-994, "CEOG Joint Applications Report on Safety Injection Tank AOT/SIT Extension," April 1995.

3/4.5.1 SAFETY INJECTION TANKS (continued)

within 6 hours and pressurizer pressure reduced to < 1750 psia within 12 hours. The allowed completion times are reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

If more than one SIT is inoperable, the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

LCO 3.5.1.a requires that each reactor coolant system safety injection tank shall be OPERABLE with the isolation valve open and the power to the valve operator removed.

This is to ensure that the valve is open and cannot be inadvertently closed. To meet LCO 3.5.1.a requirements, the valve operator is considered to be the valve motor and not the motor control circuit. Removing the closing coil while maintaining the breaker closed meets the intent of the Technical Specification by ensuring that the valve cannot be inadvertently closed.

Removing the closing coil and verifying that the closing coil is removed (Per SR 4.5.1.e) meets the Technical Specification because it prevents energizing the valve operator to position the valve in the close direction.

Opening the breaker, in lieu of removing the closing coil, to remove power to the valve operator is not a viable option since:

1. Millstone Unit 2 Safety Evaluation Report (SER) Docket No. 50-336, dated May 10, 1974, requires two independent means of position indication.

2. Surveillance Requirement 4.5.1.a requires the control/indication circuit to be energized, to verify that the valve is open.

3. Technical Specification 3/4.3.2, Engineered Safety Feature Actuation System Instrumentation, requires these valves to open on a SIAS signal.

Opening the breaker would eliminate the ability to satisfy the above three items.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two separate and independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the safety injection tanks is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double ended break of the largest RCS cold leg pipe downward.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (continued)

Each Emergency Core Cooling System (ECCS) subsystem required by Technical Specification 3.5.2 for design basis accident mitigation includes an OPERABLE high pressure safety injection (HPSI) pump and a low pressure safety injection (LPSI) pump. Each of these pumps requires an OPERABLE flow path capable of taking suction from the refueling water storage tank (RWST) on a safety injection actuation signal (SIAS). Upon depletion of the inventory in the RWST, as indicated by the generation of a Sump Recirculation Actuation Signal (SRAS), the suction for the HPSI pumps will automatically be transferred to the containment sump. The SRAS will also secure the LPSI pumps. The ECCS subsystems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) as design basis accident mitigation equipment.

Flow from the charging pumps is no longer required for design basis accident mitigation. The loss of coolant accident analysis has been revised and no credit is taken for charging pump flow. As a result, the charging pumps no longer meet the first three criteria of 10CFR 50.36 (c)(2)(ii) as design basis accident mitigation equipment required to be controlled by Technical Specifications. In addition, risk evaluations have been performed to demonstrate that the charging system is not risk significant as defined in 10CFR 50.36(c)(2)(ii) Criterion 4. However, the charging system is credited in the PRA model for mitigating two beyond design basis events, Anticipated Transients Without Scram (ATWS) and Complete Loss of Secondary Heat Sink. On this basis, the requirements for charging pump OPERABILITY will be retained in Technical Specification 3.5.2. Consistent with the surveillance requirements, only the charging pump will be included in determining ECCS subsystem OPERABILITY.

As a result of the risk insight, the charging pump will be included as an Emergency Core Cooling System subsystem required by Technical Specification 3.5.2. That is, an ECCS subsystem will include one OPERABLE charging pump. The charging pump credited for each ECCS subsystem must meet the surveillance requirements specified in Section 4.5.2. Consistent with the risk insights, automatic start of the charging pump is not required for compliance to TS 3.5.2. Thus, Section 4.5.2 does not specify any testing requirements for the automatic start of the credited charging pump. Similarly, since the ECCS flow path is not credited in the risk evaluation, there are no charging flow path requirements included in TS 3.5.2.

The requirements for automatic actuation of the charging pumps and the associated boration system components (boric acid pumps, gravity feed valves, boric acid flow path valves), which align the boric acid storage tanks to the charging pump suction on a SIAS have been relocated to the Technical Requirements Manual. These relocated requirements do not affect the OPERABILITY of the charging pumps for Technical Specification 3.5.2

Bases Change of 6-28-2005

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (continued)

Surveillance Requirement 4.5.2.a verifies the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths to provide assurance that the proper flow paths will exist for ECCS operation. This surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

Surveillance Requirement 4.5.2.b verifies proper valve position to ensure that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removing power to the valve operator ensures that the valves cannot be inadvertently misaligned or change position as the result of an active failure. A 31 day frequency is considered reasonable in view of other administrative controls ensuring that a mispositioned valve is an unlikely possibility.

Surveillance Requirements 4.5.2.c and 4.5.2.d, which address periodic surveillance testing of the ECCS pumps (high pressure and low pressure safety injection pumps) to detect gross degradation caused by impeller structural damage or other hydraulic component problems, is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the unit safety analysis. The surveillance requirements are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and frequencies necessary to satisfy the requirements.

Surveillance Requirement 4.5.2.e, which addresses periodic surveillance testing of the charging pumps to detect gross degradation caused by hydraulic component problems, is required by Section XI of the ASME Code. For positive displacement pumps, this type of testing may be accomplished by comparing the measured pump flow, discharge pressure and vibration to their respective acceptance criteria. Acceptance criteria are verified to bound the assumptions utilized in accident analyses. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test point is greater than or equal to the performance assumed for mitigation of the beyond design basis events. The surveillance requirements are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and frequencies necessary to satisfy the requirements.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (continued)

Surveillance Requirements 4.5.2.f, 4.5.2.g, and 4.5.2.h demonstrate that each automatic ECCS flow path valve actuates to the required position on an actual or simulated actuation signal (SIAS or SRAS), that each ECCS pump starts on receipt of an actual or simulated actuation signal (SIAS), and that the LPSI pumps stop on receipt of an actual or simulated actuation signal (SRAS). This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage, and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

Surveillance Requirement 4.5.2.i verifies the high and low pressure safety injection valves listed in Table 4.5-1 will align to the required positions on an SIAS for proper ECCS performance. The safety injection valves have stops to position them properly so that flow is restricted to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

Surveillance Requirement 4.5.2.j addresses periodic inspection of the containment sump to ensure that it is unrestricted and stays in proper operating condition. The 18 month frequency is based on the need to perform this surveillance under the conditions that apply during an outage, and the need to have access to the location. This frequency is sufficient to detect abnormal degradation and is confirmed by operating experience.

Surveillance Requirement 4.5.2.k verifies that the Shutdown Cooling (SDC) System open permissive interlock is OPERABLE to ensure the SDC suction isolation valves are prevented from being remotely opened when RCS pressure is at or above the SDC suction design pressure of 300 psia. The suction piping of the SDC pumps (low pressure safety injection pumps) is the SDC component with the limiting design pressure rating. The interlock provides assurance that double isolation of the SDC System from the RCS is preserved whenever RCS pressure is at or above the design pressure. The 18 month frequency is based on the need to perform this surveillance under the conditions that apply during an outage. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (continued

Only one ECCS subsystem is required by Technical Specification 3.5.3 for design basis accident mitigation. This ECCS subsystem requires one OPERABLE HPSI pump and an OPERABLE flow path capable of taking suction from the RWST on a SIAS. Upon depletion of the inventory in the RWST, as indicated by the generation of a SRAS, the suction for the HPSI pump will automatically be transferred to the containment sump. This ECCS subsystem satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) as design basis accident mitigation equipment.

Surveillance Requirement 4.5.3.1 specifies the surveillance requirements of Technical Specification 3.5.3 that are required to demonstrate that the required ECCS subsystem of Technical Specification 3.5.3 is OPERABLE. The required ECCS subsystem of Technical Specification 3.5.3 does not include any LPSI components. LPSI components are not required when Technical Specification 3.5.3 is applicable to allow the LPSI components to be used for SDC System operation.

In MODE 4 the automatic safety injection signal generated by low pressurizer pressure and high containment pressure and the automatic sump recirculation actuation signal generation by low refueling water storage tank level are not required to be OPERABLE. Automatic actuation in MODE 4 is not required because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating engineered safety features components. Since the manual actuation (trip pushbuttons) portion of the safety injection and sump recirculation actuation signal generation is required to be OPERABLE in MODE 4, the plant operators can use the manual trip pushbuttons to rapidly position all components to the required accident position. Therefore, the safety injection and sump recirculation actuation trip pushbuttons satisfy the requirement for generation of safety injection and sump recirculation actuation signals in MODE 4.

In MODE 4, the OPERABLE HPSI pump is not required to start automatically on a SIAS. Therefore, the pump control switch for this OPERABLE pump may be placed in the pull-to-lock position without affecting the OPERABILITY of the pump. This will prevent the pump from starting automatically, which could result in overpressurization of the Shutdown Cooling System. Only one HPSI pump may be OPERABLE in MODE 4 with RCS temperatures less than or equal to 275°F due to the restricted relief capacity with Low-Temperature Overpressure Protection System. To reduce shutdown risk by having additional pumping capacity readily available, a HPSI pump may be made inoperable but available at short notice by shutting its discharge valve with the key lock on the control panel.

Bases Change of 6-28-2005

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

BASES:

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (continued

The provision in Specification 3.5.3 that Specifications 3.0.4 and 4.0.4 are not applicable for entry into MODE 4 is provided to allow for connecting the HPSI pump breaker to the respective power supply or to remove the tag and open the discharge valve, and perform the subsequent testing necessary to declare the inoperable HPSI pump OPERABLE. Specification 3.4.9.3 requires all HPSI pumps to be not capable of injecting into the RCS when RCS temperature is at or below 190°F. Once RCS temperature is above 190°F one HPSI pump can be capable of injecting into the RCS. However, sufficient time may not be available to ensure one HPSI pump is OPERABLE prior to entering MODE 4 as required by Specification 3.5.3. Since Specifications 3.0.4 and 4.0.4 prohibit a MODE change in this situation, this exemption will allow Millstone Unit No. 2 to enter MODE 4, take the steps necessary to make the HPSI pump capable of injecting into the RCS, and then declare the pump OPERABLE. If it is necessary to use this exemption during plant heatup, the appropriate ACTION statement of Specification 3.5.3 should be entered as soon as MODE 4 is reached.

3/4.5.4 REFUELING WATER STORAGE TANK (RWST)

The OPERABILITY of the RWST as part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA. The limits on RWST minimum volume and boron concentration ensure that 1) sufficient water is available within containment to permit recirculation cooling flow to the core, and 2) after a LOCA the reactor will remain subcritical in the cold condition following mixing of the RWST and the RCS water volumes. Small break LOCAs assume that all control rods are inserted, except for the control element assembly (CEA) of highest worth, which remains withdrawn from the core. Large break LOCAs assume that all CEAs remain withdrawn from the core.

3/4.5.5 TRISODIUM PHOSPHATE (TSP)

The trisodium phosphate (TSP) dodecahydrate stored in dissolving baskets located in the containment basement is provided to minimize the possibility of corrosion cracking of certain metal components during operation of the ECCS following a LOCA. The TSP provides this protection by dissolving in the sump water and causing its final pH to be raised ≥ 7.0. This determination assumes the RCS, the SI tanks, and the RWST are at a maximum boron concentration of 2400 ppm and the BASTs are at a maximum boron concentration of 3.5 weight percent.

The requirement to dissolve a representative sample of TSP in a sample of borated water provides assurance the stored TSP will dissolve in borated water at postulated post-LOCA temperatures. This test is performed by submerging a representative sample of 0.6662 ± 0.0266 grams of TSP from one of the baskets in containment in 250 ± 10 milliliters of water at a boron concentration of 2482 ± 20 ppm, and a temperature of 77 ± 5°F. Without agitation, the solution is allowed to stand for four hours. The liquid is then decanted, mixed, and the pH measured. The pH must be ≥ 7.0. The representative TSP sample weight is based on the minimum required TSP mass of 12,042 pounds, which at the manufactured density corresponds to the minimum volume of 223 ft^3 (The minimum Technical Specification requirement of 282 ft^3 is based on 223 ft^3 of TSP for boric acid neutralization and 59 ft^3 of TSP for neutralization of hydrochloric and nitric acids.), and the maximum sump water volume (at 77°F) following a LOCA of 2,046,441 liters, normalized to buffer a 250 ± 10 milliliter sample. The boron concentration of the test water is representative of the maximum possible concentration in the sump following a LOCA. Agitation of the test solution is prohibited during TSP dissolution since an adequate standard for the agitation intensity cannot be specified. The dissolution time of four hours is necessary to allow time for the dissolved TSP to naturally diffuse through the sample solution. In the containment sump following a LOCA, rapid mixing will occur, significantly decreasing the actual amount of time before the required pH is achieved. The solution is decanted after the four hour period to remove any undissolved TSP prior to mixing and pH measurement. Mixing is necessary for proper operation of the pH instrument.

3/4.6 CONTAINMENT SYSTEMS

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 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 100 during accident conditions.

Primary CONTAINMENT INTEGRITY is required in MODES 1 through 4. This requires an OPERABLE containment automatic isolation valve system. In MODES 1, 2, and 3 this is satisfied by the automatic containment isolation signals generated by low pressurizer pressure and high containment pressure. In MODE 4 the automatic containment isolation signals generated by low pressurizer pressure and high containment pressure are not required to be OPERABLE. Automatic actuation of the containment isolation system in MODE 4 is not required because adequate time is available for plant operators to evaluate plant conditions and respond by manually operating engineered safety features components. Since the manual actuation (trip pushbuttons) portion of the containment isolation system is required to be OPERABLE in MODE 4, the plant operators can use the manual pushbuttons to rapidly position all automatic containment isolation valves to the required accident position. Therefore, the containment isolation trip pushbuttons satisfy the requirement for an OPERABLE containment automatic isolation valve system in MODE 4.

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 P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to $< 0.75\ L_a$ during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates is in accordance with the Containment Leakage Rate Testing Program.

The Millstone Unit No. 2 FSAR contains a list of the containment penetrations that have been identified as secondary containment bypass leakage paths.

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 CONTAINMENT INTEGRITY and leak rate given in Specifications 3.6.1.1 and

3.6.1.2. The limitations on the air locks allow entry and exit into and out of the containment during operation and ensure through the surveillance testing that air lock leakage will not become excessive through continuous usage.

The ACTION requirements are modified by a Note that allows entry and exit to perform repairs on the affected air lock components. This means there may be a short time during which the containment boundary is not intact (e.g., during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed.

ACTION a. is only applicable when one air lock door is inoperable. With only one air lock door inoperable, the remaining OPERABLE air lock door must be verified closed within 1 hour. This ensures a leak tight containment barrier is maintained by use of the remaining OPERABLE air lock door. The 1 hour requirement is consistent with the requirements of Technical Specification 3.6.1.1 to restore CONTAINMENT INTEGRITY. In addition, the remaining OPERABLE air lock door must be locked closed within 24 hours and then verified periodically to ensure an acceptable containment leakage boundary is maintained. Otherwise, a plant shutdown is required.

ACTION b. is only applicable when the air lock door interlock mechanism is inoperable. With only the air lock interlock mechanism inoperable, an OPERABLE air lock door must be verified closed within 1 hour. This ensures a leak tight containment barrier is maintained by use of an OPERABLE air lock door. The 1 hour requirement is consistent with the requirements of Technical Specification 3.6.1.1 to restore CONTAINMENT INTEGRITY. In addition, an OPERABLE air lock door must be locked closed within 24 hours and then verified periodically to ensure an acceptable containment leakage boundary is maintained. Otherwise, a plant shutdown is required. In addition, entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock) is permitted.

ACTION c. is applicable when both air lock doors are inoperable, or the air lock is inoperable for any other reason excluding the door interlock mechanism. With both air lock doors inoperable or the air lock otherwise inoperable, an evaluation of the overall containment leakage rate per Specification 3.6.1.2 shall be initiated immediately, and an air lock door must be verified closed within 1 hour. An evaluation is acceptable since it is overly conservative to immediately declare the containment inoperable if both doors in the air lock have failed a seal test or if overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per Specification 3.6.1.1) would be provided to restore the air lock to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits. The 1 hour requirement is consistent with the requirements of Technical Specification 3.6.1.1 to restore CONTAINMENT INTEGRITY. In addition, the air lock and/or at least one air lock door must be restored to OPERABLE status within 24 hours or a plant shutdown is required.

BASES

Continued

Surveillance Requirement 4.6.1.3.1 verifies leakage through the containment air lock is within the requirements specified in the Containment Leakage Rate Testing Program. The containment air lock leakage results are accounted for in the combined Type B and C containment leakage rate. Failure of an air lock door does not invalidate the previous satisfactory overall air lock leakage test because either air lock door is capable of providing a fission product barrier in the event of a design basis accident.

3/4.6.1.4 INTERNAL PRESSURE

The limitations on containment internal pressure ensure that the containment peak pressure does not exceed the design pressure of 54 psig during MSLB or LOCA conditions.

The maximum peak pressure is obtained from a MSLB event. The limit of 1.0 psig for initial positive containment pressure will limit the total pressure to less than the design pressure and is consistent with the accident analyses.

3/4.6.1.5 AIR TEMPERATURE

The limitation on containment air temperature ensures that the containment air temperature does not exceed the worst case combined LOCA/MSLB air temperature profile and the liner temperature of 289°F. The containment air and liner temperature limits are consistent with the accident analyses.

The temperature detectors used to monitor primary containment air temperature are located on the 38 ft. 6 in. floor elevation in containment. The detectors are located approximately 6 feet above the floor, on the southeast and southwest containment walls.

3/4.6.1.6 DELETED

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY AND COOLING SYSTEMS

The OPERABILITY of the containment spray system ensures that containment depressurization and cooling capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the accident analyses.

The OPERABILITY of the containment cooling system ensures that 1) the containment air temperature will be maintained within limits during normal operation, and 2) adequate heat removal capacity is available when operated in conjunction with the containment spray system during post-LOCA conditions.

To be OPERABLE, the two trains of the containment spray system shall be capable of taking a suction from the refueling water storage tank on a containment spray actuation signal and automatically transferring suction to the containment sump on a sump recirculation actuation signal. Each containment spray train flow path from the containment sump shall be via an OPERABLE shutdown cooling heat exchanger.

The containment cooling system consists of two containment cooling trains. Each containment cooling train has two containment air recirculation and cooling units. For the purpose of applying the appropriate ACTION statement, the loss of a single containment air recirculation and cooling unit will make the respective containment cooling train inoperable.

Either the containment spray system or the containment cooling system is sufficient to mitigate a loss of coolant accident. The containment spray system is more effective than the containment cooling system in reducing the temperature of superheated steam inside containment following a main steam line break. Because of this, the containment spray system is required to mitigate a main steam line break accident inside containment. In addition, the containment spray system provides a mechanism for removing iodine from the containment atmosphere. Therefore, at least one train of containment spray is required to be OPERABLE when pressurizer pressure is ≥ 1750 psia, and the allowed outage time for one train of containment spray reflects the dual function of containment spray for heat removal and iodine removal.

Surveillance Requirement 4.6.2.1.1.a verifies the correct alignment for manual, power operated, and automatic valves in the Containment Spray System flow paths to provide assurance that the proper flow paths will exist for containment spray operation. This surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

Bases Change of 6-28-2005

3/4.6.2.1 CONTAINMENT SPRAY AND COOLING SYSTEMS (Continued)

Surveillance Requirement 4.6.2.1.1.b, which addresses periodic surveillance testing of the containment spray pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems, is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the unit safety analysis. The surveillance requirements are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and frequencies necessary to satisfy the requirements.

Surveillance Requirements 4.6.2.1.1.c and 4.6.2.1.1.d demonstrate that each automatic containment spray valve actuates to the required position on an actual or simulated actuation signal (CSAS or SRAS), and that each containment spray pump starts on receipt of an actual or simulated actuation signal (CSAS). This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

Surveillance Requirement 4.6.2.1.1.e demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. This surveillance is normally performed by blowing low pressure air or smoke through test connections with the containment spray inlet valves closed and the spray header drained of any solution. Due to the passive design of the nozzles, a test at 10 year intervals is considered adequate to detect obstruction of the spray nozzles.

Surveillance Requirement 4.6.2.1.2.a demonstrates that each containment air recirculation and cooling unit can be operated in slow speed for $\geq$ 15 minutes to ensure OPERABILITY and that all associated controls are functioning properly. It also ensures fan or motor failure can be detected and corrective action taken. The 31 day frequency considers the known reliability of the fan units and controls, the two train redundancy available, and the low probability of a significant degradation of the containment air recirculation and cooling unit occurring between surveillances. This frequency has been shown to be acceptable through operating experience.

3/4.6.2.1 CONTAINMENT SPRAY AND COOLING SYSTEMS (Continued)

Surveillance Requirement 4.6.2.1.2.b demonstrates a cooling water flow rate of $\geq$ 500 gpm to each containment air recirculation and cooling unit to provide assurance a cooling water flow path through the cooling unit is available. The 31 day frequency considers the known reliability of the cooling water system, the two train redundancy available, and the low probability of a significant degradation of flow occurring between surveillances. This frequency has been shown to be acceptable through operating experience.

Surveillance Requirement 4.6.2.1.2.c demonstrates that each containment air recirculation and cooling unit starts on receipt of an actual or simulated actuation signal (SIAS). The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

3/4.6.3 CONTAINMENT ISOLATION VALVES

The Technical Requirements Manual contains the list of containment isolation valves (except the containment air lock and equipment hatch). Any changes to this list will be reviewed under 10CFR50.59 and approved by the committee(s) as described in the QAP Topical Report.

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The containment isolation valves are used to close all fluid (liquid and gas) penetrations not required for operation of the engineered safety feature systems, to prevent the leakage of radioactive materials to the environment. The fluid penetrations which may require isolation after an accident are categorized as Type P, O, or N. The penetration types are listed with the containment isolation valves in the Technical Requirements Manual.

Type P penetrations are lines that connect to the reactor coolant pressure boundary (Criterion 55 of 10CFR50, Appendix A). These lines are provided with two containment isolation valves, one inside containment, and one outside containment.

Type O penetrations are lines that are open to the containment internal atmosphere (Criterion 56 of 10CFR50, Appendix A). These lines are provided with two containment isolation valves, one inside containment, and one outside containment.

3/4.6.3 CONTAINMENT ISOLATION VALVES (continued)

Type N penetrations are lines that neither connect to the reactor coolant pressure boundary nor are open to the containment internal atmosphere, but do form a closed system within the containment structure (Criterion 57 of 10CFR50, Appendix A). These lines are provided with single containment isolation valves outside containment. These valves are either remotely operated or locked closed manual valves.

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration.

If the containment isolation valve on a closed system becomes inoperable, the remaining barrier is a closed system since a closed system is an acceptable alternative to an automatic valve. However, ACTIONS must still be taken to meet Technical Specification ACTION 3.6.3.1.d and the valve, not normally considered as a containment isolation valve, and closest to the containment wall should be put into the closed position. No leak testing of the alternate valve is necessary to satisfy the ACTION statement. Placing the manual valve in the closed position sufficiently deactivates the penetration for Technical Specification compliance. Closed system isolation valves applicable to Technical Specification ACTION 3.6.3.1.d are included in FSAR Table 5.2-11, and are the isolation valves for those penetrations credited as General Design Criteria 57, (Type N penetrations). The specified time (i.e., 72 hours) of Technical Specification ACTION 3.6.3.1.d is reasonable, considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4. In the event the affected penetration is isolated in accordance with 3.6.3.1.d, the affected penetration flow path must be verified to be isolated on a periodic basis, (Surveillance Requirement 4.6.1.1.a). This is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The frequency of once per 31 days in this surveillance for verifying that each affected penetration flow path is isolated is appropriate considering the valves are operated under administrative controls and the probability of their misalignment is low.

For the purposes of meeting this LCO, neither the containment isolation valve, nor any alternate valve on a closed system have a leakage limit associated with valve OPERABILITY.

Bases Change of 6-28-2005

3/4.6.3 CONTAINMENT ISOLATION VALVES (continued)

Containment isolation valves may be opened on an intermittent basis provided appropriate administrative controls are established. The position of the NRC concerning acceptable administrative controls is contained in Generic Letter 91-08, "Removal of Component Lists from Technical Specifications," and includes the following considerations:

(1) stationing an operator, who is in constant communication with the control room, at the valve controls,

(2) instructing this operator to close these valves in an accident situation, and

(3) assuring that environmental conditions will not preclude access to close the valve and that this action will prevent the release of radioactivity outside the containment.

The appropriate administrative controls, based on the above considerations, to allow containment isolation valves to be opened are contained in the procedures that will be used to operate the valves. Entries should be placed in the Shift Manager Log when these valves are opened and closed. However, it is not necessary to log into any Technical Specification ACTION Statement for these valves, provided the appropriate administrative controls have been established.

If a containment isolation valve is opened while operating in accordance with Abnormal or Emergency Operating Procedures (AOPs and EOPs), it is not necessary to establish a dedicated operator. The AOPs and EOPs provide sufficient procedural control over the operation of the containment isolation valves.

Opening a closed containment isolation valve bypasses a plant design feature that prevents the release of radioactivity outside the containment. Therefore, this should not be done frequently, and the time the valve is opened should be minimized. As a general guideline, a closed containment isolation valve should not be opened longer than the time allowed to restore the valve to OPERABLE status, as stated in the ACTION statement for LCO 3.6.3.1 "Containment Isolation Valves."

A discussion of the appropriate administrative controls for the containment isolation valves, that are expected to be opened during operation in MODES 1 through 4, is presented below.

Manual containment isolation valve 2-SI-463, safety injection tank (SIT) recirculation header stop valve, is opened to fill or drain the SITs and for Shutdown Cooling System (SDC) boron equalization. While 2-SI-463 is open, a dedicated operator, in continuous communication with the control room, is required.

Bases Change of 6-28-2005

3/4.6.3 CONTAINMENT ISOLATION VALVES (continued)

When SDC is initiated, SDC suction isolation remotely operated valves 2-SI-652 and 2-SI-651 (inside containment isolation valve) and manual valve 2-SI-709 (outside containment isolation valve) are opened. 2-SI-651 is normally operated from the control room. While in MODES 1, 2 or 3, 2-SI-651 is closed with manual disconnect switch NSI651 locked open to satisfy Appendix R requirements. It does not receive an automatic containment isolation closure signal, but is interlocked to prevent opening if Reactor Coolant System (RCS) pressure is greater than approximately 275 psia. When 2-SI-651 is opened from the control room, either one of the two required licensed (Reactor Operator) control room operators can be credited as the dedicated operator required for administrative control. It is not necessary to use a separate dedicated operator.

When valve 2-SI-709 is opened locally, a separate dedicated operator is not required to remain at the valve. 2-SI-709 is opened before 2-SI-651. Therefore, opening 2-SI-709 will not establish a connection between the RCS and the SDC System. Opening 2-SI-651 will connect the RCS and SDC System. If a problem then develops, 2-SI-651 can be closed from the control room.

The administrative controls for valves 2-SI-651 and 2-SI-709 apply only during preparations for initiation of SDC, and during SDC operations. They are acceptable because RCS pressure and temperature are significantly below normal operating pressure and temperature when 2-SI-651 and 2-SI-709 are opened, and these valves are not opened until shortly before SDC flow is initiated. The penetration flowpath can be isolated from the control room by closing either 2-SI-652 or 2-SI-651, and the manipulation of these valves, during this evolution, is controlled by plant procedures.

The pressurizer auxiliary spray valve, 2-CH-517, can be used as an alternate method to decrease pressurizer pressure, or for boron precipitation control following a loss of coolant accident. When this valve is opened from the control room, either one of the two required licensed (Reactor Operator) control room operators can be credited as the dedicated operator required for administrative control. It is not necessary to use a separate dedicated operator.

The exception for 2-CH-517 is acceptable because the fluid that passes through this valve will be collected in the Pressurizer (reverse flow from the Pressurizer to the charging system is prevented by check valve 2-CH-431), and the penetration associated with 2-CH-517 is open during accident conditions to allow flow from the charging pumps. Also, this valve is normally operated from the control room, under the supervision of the licensed control room operators, in accordance with plant procedures.

A dedicated operator is not required when opening remotely operated valves associated with Type N fluid penetrations (Criterion 57 of 10CFR50, Appendix A). Operating these valves from the control room is sufficient. The main steam isolation valves (2-MS-64A and 64B), atmospheric steam dump valves (2-MS-190A and 190B), and the containment air recirculation cooler RBCCW discharge valves (2-RB-28.2A-D) are examples of remotely operated containment isolation valves associated with Type N fluid penetrations.

Bases Change of 6-28-2005

3/4.6.3 CONTAINMENT ISOLATION VALVES (continued)

MSIV bypass valves 2-MS-65A and 65B are remotely operated MOVs, but while in MODE 1, they are closed with power to the valve motors removed via lockable disconnect switches located at their respective MCC to satisfy Appendix "R" requirements.

Local operation of the atmospheric steam dump valves (2-MS-190A and 190B), or other remotely operated valves associated with Type N fluid penetrations, will require a dedicated operator in constant communication with the control room, except when operating in accordance with AOPs or EOPs. Even though these valves can not be classified as locked or sealed closed, the use of a dedicated operator will satisfy administrative control requirements. Local operation of these valves with a dedicated operator is equivalent to the operation of other manual (locked or sealed closed) containment isolation valves with a dedicated operator.

The main steam supplies to the turbine driven auxiliary feedwater pump (2-MS-201 and 2-MS-202) are remotely operated valves associated with Type N fluid penetrations. These valves are maintained open during power operation. 2-MS-201 is maintained energized, so it can be closed from the control room, if necessary, for containment isolation. However, 2-MS-202 is deenergized open by removing power to the valve's motor via a lockable disconnect switch to satisfy Appendix R requirements. Therefore, 2-MS-202 cannot be closed immediately from the control room, if necessary, for containment isolation. The disconnect switch key to power for 2-MS-202 is stored in the Unit 2 control room, and can be used to re-power the valve at the MCC; this will allow the valve to be closed from the control room. It is not necessary to maintain a dedicated operator at 2-MS-202 because this valve is already in the required accident position. Also, the steam that passes through this valve should not contain any radioactivity. The steam generators provide the barrier between the containment and the atmosphere. Therefore, it would take an additional structural failure for radioactivity to be released to the environment through this valve.

Steam generator chemical addition valves, 2-FW-15A and 2-FW-15B, are opened to add chemicals to the steam generators using the Auxiliary Feedwater System (AFW). When either 2-FW-15A or 2-FW-15B is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of these valves is expected during plant startup and shutdown.

The bypasses around the main steam supplies to the turbine driven auxiliary feedwater pump (2-MS-201 and 2-MS-202), 2-MS-458 and 2-MS-459, are opened to drain water from the steam supply lines. When either 2-MS-458 or 2-MS-459 is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of these valves is expected during plant startup.

The containment station air header isolation, 2-SA-19, is opened to supply station air to containment. When 2-SA-19 is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of this valve is only expected for maintenance activities inside containment.

The backup air supply master stop, 2-IA-566, is opened to supply backup air to 2-CH-517, 2-CH-518, 2-CH-519, 2-EB-88, and 2-EB-89. When 2-IA-566 is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of this valve is only expected in response to a loss of the normal air supply to the valves listed.

3/4.6.3 CONTAINMENT ISOLATION VALVES (continued)

The nitrogen header drain valve, 2-SI-045, is opened to depressurize the containment side of the nitrogen supply header stop valve, 2-SI-312. When 2-SI-045 is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of this valve is only expected after using the high pressure nitrogen system to raise SIT nitrogen pressure.

The containment waste gas header test connection isolation valve, 2-GR-63, is opened to sample the primary drain tank for oxygen and nitrogen. When 2-GR-63 is opened, a dedicated operator, in continuous communication with the control room, is required. Operation of this valve is expected during plant startup and shutdown.

The upstream vent valves for the steam generator atmospheric dump valves, 2-MS-369 and 2-MS-371, are opened during steam generator safety valve set point testing to allow steam header pressure instrumentation to be placed in service. When either 2-MS-369 or 2-MS-371 is opened, a dedicated operator in continuous communication with the control room is required.

The determination of the appropriate administrative controls for these containment isolation valves included an evaluation of the expected environmental conditions. This evaluation has concluded environmental conditions will not preclude access to close the valve, and this action will prevent the release of radioactivity outside of containment through the respective penetration.

The containment purge supply and exhaust isolation valves are required to be sealed closed during plant operation since these valves have not been demonstrated capable of closing during a LOCA or steam line break accident. Such a demonstration would require justification of the mechanical OPERABILITY of the purge valves and consideration of the appropriateness of the electrical override circuits. Maintaining these valves closed during plant operations ensures that excessive quantities of radioactive materials will not be released via the containment purge system. The containment purge supply and exhaust isolation valves are sealed closed by removing power from the valves. This is accomplished by pulling the control power fuses for each of the valves. The associated fuse blocks are then locked. This is consistent with the guidance contained in NUREG-0737 Item II.E.4.2 and Standard Review Plan 6.2.4, "Containment Isolation System," Item II.f.

Surveillance Requirement 4.6.3.1.a verifies the isolation time of each power operated automatic containment isolation valve is within limits to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation time and surveillance frequency are in accordance with the Inservice Testing Program.

Surveillance Requirement 4.6.3.1.b demonstrate that each automatic containment isolation valve actuates to the isolation position on an actual or simulated containment isolation signal [containment isolation actuation signal (CIAS) or containment high radiation actuation signal (containment purge valves only)]. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillance was performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

Bases Change of 6-28-2005

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions. Either recombiner unit is 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. This hydrogen control system is consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA."

The post-incident recirculation systems are provided to ensure adequate mixing of the containment atmosphere following a LOCA. This mixing action will prevent localized accumulations of hydrogen from exceeding the flammable limit.

3/4.6.5 SECONDARY CONTAINMENT

3/4.6.5.1 ENCLOSURE BUILDING FILTRATION SYSTEM

The OPERABILITY of the Enclosure Building Filtration System ensures that containment leakage occurring during LOCA conditions into the annulus will be filtered through the HEPA filters and charcoal adsorber trains prior to discharge to the atmosphere. This requirement is necessary to meet the assumptions used in the accident analyses and limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR 100 during LOCA conditions.

The laboratory testing requirement for the charcoal sample to have a removal efficiency of ≥ 95% is more conservative than the elemental and organic iodine removal efficiencies of 90% and 70%, respectively, assumed in the DBA analyses for the EBFS charcoal adsorbers in the Millstone Unit 2 Final Safety Analysis Report. A removal efficiency acceptance criteria of ≥ 95% will ensure the charcoal has the capability to perform its intended safety function throughout the length of an operating cycle.

Surveillance Requirement 4.6.5.1.b.1 dictates the test frequency, method and acceptance criteria for the EBFS trains (cleanup trains). These criteria all originate in the Regulatory Position sections of Regulatory Guide 1.52, Rev. 2, March 1978 as discussed below:

Section C.5.a requires a visual inspection of the cleanup system be made before the following tests, in accordance with the provisions of section 5 of ANSI N510-1975:

- in-place air flow distribution test
- DOP test
- activated carbon adsorber section leak test

Section C.5.c requires the in-place Dioctyl phthalate (DOP) test for HEPA filters to conform to section 10 of ANSI N510-1975. The HEPA filters should be tested in place (1) initially, (2) at least once per 18 months thereafter, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. The testing is to confirm a penetration of less than 0.05%* at rated flow. A filtration system satisfying this criteria can be considered to warrant a 99% removal efficiency for particulates.

Section C.5.d requires the charcoal adsorber section to be leak tested with a gaseous halogenated hydrocarbon refrigerant, in accordance with section 12 of ANSI N510-1975 to ensure that bypass leakage through the adsorber section is less than 0.05%.** Adsorber leak testing should be conducted (1) initially, (2) at least once per 18 months thereafter, (3) following removal of an adsorber sample for laboratory testing if the integrity of the adsorber

---

* Means that the HEPA filter will allow passage of less than 0.05% of the test concentration injected at the filter inlet from a standard DOP concentration injection.

** Means that the charcoal adsorber sections will allow passage of less than 0.05% of the injected test concentration around the charcoal adsorber sections.

Bases Change of 6-28-2005

Section C.5.d (Continued)

section is affected, and (4) following painting, fire, or chemical release in any ventilation zone communicating with the system.

3/4.6.5.2 ENCLOSURE BUILDING

The OPERABILITY of the Enclosure Building ensures that the releases of radioactive materials from the primary containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with operation of the Enclosure Building Filtration System, will limit the SITE BOUNDARY radiation doses to within the limits of 10 CFR 100 during accident conditions.

One Enclosure Building Filtration System train is required to establish a negative pressure of 0.25 inches W.G. in the Enclosure Building Filtration Region within one minute after an Enclosure Building Filtration Actuation Signal is generated. The one minute time requirement does not include the time necessary for the associated emergency diesel generator to start and power Enclosure Building Filtration System equipment.

To enable the Enclosure Building Filtration System to establish the required negative pressure in the Enclosure Building, it is necessary to ensure that all Enclosure Building access openings are closed. For double door access openings, only one door is required to be closed and latched, except for normal passage. For single door access openings, that door is required to be closed and latched, except for normal passage.

If a required door that is designated to automatically close and latch is not capable of automatically closing and latching, the door shall be maintained closed and latched, or personnel shall be stationed at the door to ensure that the door is closed and latched after each transit through the door. Otherwise, the access opening (door) should be declared inoperable and appropriate technical specification ACTION statement entered.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves (MSSVs) ensures that the secondary system pressure will be limited to within 110% of the design pressure during the most severe anticipated system operational transient. The Loss of Electrical Load with Turbine Trip and the single main steam isolation valve (MSIV) closure event were evaluated at various power levels with a corresponding number of inoperable MSSVs. The limiting anticipated system operational transient is the closure of a single MSIV.

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition. The total rated capacity of the main steam line code safety valves is 12.7 x 10^6 lbs/hr. This is sufficient to relieve in excess of 100% steam flow at RATED THERMAL POWER.

The LCO requires all MSSVs to be OPERABLE. An alternative to restoring the inoperable MSSV(s) to OPERABLE status is to reduce power so that the available MSSV relieving capacity meets ASME Code requirements for the power level. POWER OPERATION is allowed with inoperable MSSVs as specified within the limitations of the ACTION requirements.

Less than the full number of OPERABLE MSSVs requires limitations on allowable THERMAL POWER and adjustment to the Power Level-High trip setpoint in accordance with ACTIONS a.1 and a.2. The 4 hours provided for ACTION a.1 is a reasonable time period to reduce power level and is based on the low probability of an event occurring during this period that would require activation of the MSSVs. ACTION a.2 provides for 36 hours to reduce the Power Level-High trip setpoint. This time for ACTION a.2 is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

As described in Section 2.2.1 of the BASES, during a power reduction the Power Level-High trip setpoint automatically tracks THERMAL POWER downward so that it remains a fixed increment above the current power level, subject to a minimum value. Therefore, during short term reduced power evolutions e.g., MSSV testing, it is permissible to only reduce THERMAL POWER in accordance with ACTION a.1 (the protective function of ACTION a.2 is automatically provided due to the nature of the Power Level-High trip setpoint), provided that the MSSV testing can be completed within the 36 hours provided for ACTION a.2.

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES (Continued)

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure. and reseat when pressure has been reduced. The lift setpoints for the MSSVs are listed in Table 4.7-1. This table allows a ± 3% setpoint tolerance (allowable value) on the lift setting for OPERABILITY to account for drift over a cycle. Each MSSV is demonstrated OPERABLE, with lift settings as shown in Table 4.7-1, in accordance with Specification 4.0.5. A footnote to Table 4.7-1 requires that the lift setting be restored to within ± 1% of the setpoint (trip setpoint) following testing to allow for drift. While the lift settings are being restored to a tolerance of ± 1%, the MSSV will remain OPERABLE with lift settings out of tolerance by as much as ± 3%.

3/4.7.1.2 AUXILIARY FEEDWATER PUMPS

The OPERABILITY of the auxiliary feedwater pumps ensures that the Reactor Coolant System can be cooled down to less than 300°F from normal operating conditions in the event of a total loss of off-site power.

The FSAR Chapter 14 Loss of Normal Feedwater: (LONF) analysis evaluates the event occurring with and without offsite power available, and a single active failure. This analysis has determined that one motor driven AFW pump is not sufficient to meet the acceptance criteria. Therefore, two AFW pumps (two motor-driven AFW pumps, or one-motor driven AFW pump and the steam-driven AFW pump) are required to meet the acceptance criteria for this moderate frequency event. To meet the requirement of two AFW pumps available for mitigation, all three pumps must be OPERABLE to accommodate the failure of one pump. This is consistent with the limiting condition for operation and ACTION statements of Technical Specification 3.7.1.2.

Although not part of the bases of Technical Specification 3.7.1.2, the less conservative FSAR Chapter 10 Best Estimate Analysis of the LONF event was performed to demonstrate that one motor-driven AFW pump is adequate to remove decay heat, prevent steam generator dryout, maintain Reactor Coolant System (RCS) subcooling, and prevent pressurizer level from exceeding acceptable limits. From this best estimate analysis of the LONF event, an evaluation was performed to demonstrate that a single motor-driven AFW pump has sufficient capacity to reduce the RCS temperature to 300°F (in addition to decay heat removal) where the Shutdown Cooling System may be placed into operation for continued cooldown. As a result of these evaluations, one motor-driven AFW pump (or the steam-driven AFW pump which has twice the capacity of a motor-driven AFW pump) can meet the requirements to remove decay heat, prevent steam generator dryout, maintain RCS subcooling, prevent the pressurizer from exceeding acceptable limits, and reduce RCS temperature to 300°F.

The Auxiliary Feed Water (AFW) system is OPERABLE when the AFW pumps and flow paths required to provide AFW to the steam generators are OPERABLE. Technical Specification 3.7.1.2 requires three AFW pumps to be OPERABLE and provides ACTIONS to address inoperable AFW pumps. The AFW flow path requirements are separated into AFW pump suction flow path requirements, AFW pump discharge flow path to the common discharge header requirements, and common discharge header to the steam generators flow path requirements.

There are two AFW pump suction flow paths from the Condensate Storage Tank to the AFW pumps. One flow path to the turbine driven AFW pump, and one flow path to both motor driven AFW pumps. There are three AFW pump discharge flow paths to the common discharge header, one flow path from each of the three AFW pumps. There are two AFW discharge flow paths from the common discharge header to the steam generators, one flow path to each steam generator. With 2-FW-44 open (normal position), the discharge from any AFW pump will be supplied to both steam generators through the associated AFW regulating valves.

Bases Change of 6-28-2005

3/4.7.1.2 AUXILIARY FEEDWATER PUMPS (Continued)

2-FW-44 should remain open when the AFW system is required to be OPERABLE (MODES 1, 2, and 3). Closing 2-FW-44 places the plant in a configuration not considered as an initial condition in the Chapter 14 accident analyses. Therefore, if 2-FW-44 is closed while the plant is operating in MODES 1, 2, or 3, two AFW pumps should be considered inoperable and the appropriate ACTION requirement of Technical Specification 3.7.1.2 entered to limit plant operation in this configuration.

A flow path may be considered inoperable as the result of closing a manual valve, failure of an automatic valve to respond correctly to an actuation signal, or failure of the piping. In the case of an inoperable automatic AFW regulating valve (2-FW-43A or B), flow path OPERABILITY can be restored by use of a dedicated operator stationed at the associated bypass valve (2-FW-56A or B) as directed by OP 2322. Failure of the common discharge header piping will cause both discharge flow paths to the steam generators to be inoperable.

An inoperable suction flow path to the turbine driven AFW pump will result in one inoperable AFW pump. An inoperable suction flow path to the motor driven AFW pumps will result in two inoperable AFW pumps. The ACTION requirements of Technical Specification 3.7.1.2 are applicable based on the number of inoperable AFW pumps.

An inoperable pump discharge flow path from an AFW pump to the common discharge header will cause the associated AFW pump to be inoperable. The ACTION requirements of Technical Specification 3.7.1.2 for one AFW pump are applicable for each affected pump discharge flow path.

AFW must be capable of being delivered to both steam generators for design basis accident mitigation. Certain design basis events, such as a main steam line break or steam generator tube rupture, require that the affected steam generator be isolated, and the RCS decay heat removal safety function be satisfied by feeding and steaming the unaffected steam generator. If a failure in an AFW discharge flow path from the common discharge header to a steam generator prevents delivery of AFW to a steam generator, then the design basis events may not be effectively mitigated. In this situation, the ACTION requirements of Technical Specification 3.0.3 are applicable and an immediate plant shutdown is appropriate.

Two inoperable AFW System discharge flow paths from the common discharge header to both steam generators will result in a complete loss of the ability to supply AFW flow to the steam generators. In this situation, all three AFW pumps are inoperable and the ACTION requirements of Technical Specification 3.7.1.2. are applicable. Immediate corrective action is required. However, a plant shutdown is not appropriate until a discharge flow path from the common discharge header to one steam generator is restored.

Bases Change of 6-28-2005

3/4.7.1.2 AUXILIARY FEEDWATER PUMPS (Continued)

. During quarterly surveillance testing of the turbine driven AFW pump, valve 2-CN-27A is closed and valve 2-CN-28 is opened to prevent overheating the water being circulated. In this configuration, the suction of the turbine driven AFW pump is aligned to the Condensate Storage Tank via the motor driven AFW pump suction flow path, and the pump minimum flow is directed to the Condensate Storage Tank by the turbine driven AFW pump suction path upstream of 2-CN-27A in the reverse direction. During this surveillance, the suction path to the motor driven AFW pump suction path remains OPERABLE, and the turbine driven AFW suction path is inoperable. In this situation, the ACTION requirements of Technical Specification 3.7.1.2 for one AFW pump are applicable.

Surveillance Requirement 4.7.1.2.a verifies the correct alignment for manual, power operated, and automatic valves in the Auxiliary Feedwater (AFW) System flow paths (water and steam) to provide assurance that the proper flow paths will exist for AFW operation. This surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

Surveillance Requirement 4.7.1.2.b, which addresses periodic surveillance testing of the AFW pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems, is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the unit safety analysis. The surveillance requirements are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and frequencies necessary to satisfy the requirements. This surveillance is modified to indicate that the test can be deferred for the steam driven AFW pump until suitable plant conditions are established. This deferral is required because steam pressure is not sufficient to perform the test until after MODE 3 is entered. However, the test, if required, must be performed prior to entering MODE 2.

3/4.7.1.2 AUXILIARY FEEDWATER PUMPS (Continued)

Surveillance Requirements 4.7.1.2.c and 4.7.1.2.d demonstrate that each automatic AFW valve actuates to the required position on an actual or simulated actuation signal (AFWAS) and that each AFW pump starts on receipt of an actual or simulated actuation signal (AFWAS). This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program. These surveillances do not apply to the steam driven AFW pump and associated valves which are not automatically actuated.

Surveillance Requirement 4.7.1.2.e demonstrates the AFW System is properly aligned by verifying the flow path to each steam generator prior to entering MODE 2, after 30 cumulative days in MODE 5, MODE 6, or a defueled condition. OPERABILITY of the AFW flow paths must be verified before sufficient core heat is generated that would require operation of the AFW System during a subsequent shutdown. To further ensure AFW System alignment, the OPERABILITY of the flow paths is verified following extended outages to determine that no misalignment of valves has occurred. The frequency is reasonable, based on engineering judgment, and other administrative controls to ensure the flow paths are OPERABLE.

3/4.7.1.3 CONDENSATE STORAGE TANK

The OPERABILITY of the condensate storage tank with the minimum water volume ensures that sufficient water is available for cooldown of the Reactor Coolant System to less than 300°F in the event of a total loss of off-site power. The minimum water volume is sufficient to maintain the RCS at HOT STANDBY conditions for 10 hours with steam discharge to atmosphere. The contained water volume limit includes an allowance for water not usable due to discharge nozzle pipe elevation above tank bottom, plus an allowance for vortex formation.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant off-site radiation dose will be limited to a small fraction

3/4.7.1.4 ACTIVITY (Continued)

of 10 CFR Part 100 limits in the event of a steam line rupture. The dose calculations for an assumed steam line rupture include the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line and a concurrent loss of offsite electrical power. These values are consistent with the assumptions used in the accident analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blowdown in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

The ability of the main steam line isolation valves (MSIVs) to close is verified after the plant has been heated up. Since it is necessary to establish a high Reactor Coolant System temperature before the surveillance test can be performed, on exception to Technical Specification 4.0.4 has been added to SR 4.7.1.5 to allow entry into MODE 3. This is necessary to allow plant startup to proceed with equipment that is believed to be OPERABLE, but that cannot be verified by performance of the surveillance test until the appropriate plant conditions have been established. After entering MODE 3 and establishing the necessary plant conditions ($T_{avg} \geq 515°F$), the MSIVs will be declared inoperable if SR 4.7.1.5 has not been performed within the required frequency, plus 25%, in accordance with Technical Specifications 4.0.2 and 4.0.3. The ACTION statement for MODES 2 and 3 would then be entered. However, the required ACTIONS can be deferred for up to 24 hours (Technical Specification 4.0.3) to allow performance of SR 4.7.1.5. If the surveillance test is not performed within this 24 hour time period, the requirements of the ACTION statement for MODES 2 and 3 apply, and the MSIV(s) must be either restored to OPERABLE status or closed. Closing the MSIV(s) put the valve(s) in the required accident condition. However, the MSIV(s) may be opened to perform SR 4.7.1.5. If the MSIV(s) cannot be closed, the plant must be shut down to MODE 4.

3/4.7.1.6 MAIN FEEDWATER ISOLATION COMPONENTS (MFICS)

Feedwater isolation response time ensures a rapid isolation of feed flow to the steam generators via the feedwater regulating valves, feedwater bypass valves, and as backup, feed a feedwater isolation signal since the steam line break accident analysis credits them in prevention of feed line volume flashing in some cases. Feedwater pumps are assumed to trip immediately with an MSI signal.

3/4.7.1.7 ATMOSPHERIC DUMP VALVES

The atmospheric dump valve (ADV) lines provide a method to maintain the unit in HOT STANDBY, and to replace or supplement the condenser steam dump valves to cool the unit to Shutdown Cooling (SDC) entry conditions. Each ADV line contains an air operated ADV, and an upstream manual isolation valve. The manual isolation valves are normally open, and the ADVs closed. The ADVs, which are normally operated from the main control room, can be operated locally using a manual handwheel.

An ADV line is OPERABLE if local manual operation of the associated valves can be used to perform a controlled release of steam to the atmosphere. This is consistent with the LOCA analysis which credits local manual operation of the ADV lines for accident mitigation.

3/4.7.1.8 STEAM GENERATOR BLOWDOWN ISOLATION VALVES

The steam generator blowdown isolation valves will isolate steam generator blowdown on low steam generator water level. An auxiliary feedwater actuation signal will also be generated at this steam generator water level. Isolation of steam generator blowdown will conserve steam generator water inventory following a loss of main feedwater. The steam generator blowdown isolation valves will also close automatically upon receipt of a containment isolation signal or a high radiation signal (steam generator blowdown or condenser air ejector discharge).

3/4.7.2 DELETED

3/4.7.3 REACTOR BUILDING CLOSED COOLING WATER SYSTEM

The OPERABILITY of the Reactor Building Closed Cooling Water (RBCCW) System ensures that sufficient cooling capacity is available for continued operation of vital components and Engineered Safety Feature equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident analyses.

The RBCCW loops are redundant of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a design basis accident, one RBCCW loop is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two RBCCW loops must be OPERABLE, and independent to the extent necessary to ensure that a single failure will not result in the unavailability

3/4.7.3 REACTOR BUILDING CLOSED COOLING WATER SYSTEM (Continued)

of both RBCCW loops. At least one RBCCW loop will operate assuming the worst single active failure occurs following a design basis accident coincident with a loss of offsite power, or the worst single passive failure occurs during post-loss of coolant accident long term cooling. System design is assumed to mitigate the single active failure. System design or operator action is assumed to mitigate the passive failure.

The RBCCW System has numerous cross connection points between the redundant loops, with manual valve isolation capability. When these valves are opened, the two system loops are no longer independent. The loss of independence will result in one large RBCCW loop. This may adversely impact the ability of the RBCCW System to mitigate the design basis events if a single failure, active or passive, occurs. Opening the manual cross-connection valves during normal operation should be evaluated to ensure system stability, minimum component cooling flow requirements, and the ability to mitigate the design basis events coincident with a single failure are maintained. Continuous operation with cross-connection valves open is acceptable if the configuration has been evaluated and protection against a single failure can be demonstrated. (Several system configurations that have been evaluated and determined acceptable for continuous plant operation are identified below). If opening a cross-connection valve will result in a plant configuration that does not provide adequate protection against a single failure, the following guidance applies. If only the manual cross-connect valves have been opened, and the RBCCW System is in a normal configuration otherwise, with all system equipment OPERABLE, one RBCCW loop should be considered inoperable and the ACTION requirements of Technical Specification 3.7.3.1 applied. If the RBCCW System is not in a normal configuration otherwise and/or not all equipment is OPERABLE, both RBCCW loops should be considered inoperable and the ACTION requirements of Technical Specification 3.0.3 applied.

The loss of loop independence is equivalent to the situation where one loop is inoperable. If one loop is inoperable, the remaining OPERABLE loop will be able to meet all design basis accident functions, assuming an additional single failure does not occur. If the loops are not independent, the remaining single large OPERABLE loop will be able to meet all design basis accident functions, assuming a single failure does not occur. Operation in a plant configuration where protection against a single failure can not be shown is acceptable provided the time period in that configuration is limited to less than the Technical Specification specified allowed outage time. It is acceptable to operate in the off normal plant configurations identified in the ACTION requirements for the time periods specified due to the low probability of occurrence of a design basis event concurrent with a single failure during this limited time period. The allowed outage time for one inoperable RBCCW loop provides an appropriate limit for continued operation with only one OPERABLE RBCCW loop, and can be applied to a plant configuration where only loop independence has been compromised. The loop determined to be inoperable should be the loop that results in the most adverse plant configuration with respect to the availability of accident mitigation equipment. Restoration of loop independence within the time constraints of the allowed outage time is required, or a plant shutdown is necessary.

Revised by NRC letter dated May 1, 2002.

3/4.7.3 REACTOR BUILDING CLOSED COOLING WATER SYSTEM (Continued)

It is acceptable to operate with the RBCCW pump minimum flow valves (2-RB 107A, 2-RB-107B, 2-RB-107C), RBCCW pump sample valves (2-RB-56A, 2-RB-56B, and 2-RB-56C), and the RBCCW pump radiation monitor stop valves (2-RB-39, 2-RB-41, and 2-RB-43) open. An active single failure will not adversely impact both RBCCW loops with these valves open. In addition, protection against a passive single failure after the initiation of post - loss of coolant accident long term cooling is achieved by manually closing these accessible valves, as directed by the emergency operating procedures. In addition, operation with RBCCW chemical addition valves (2-RB-50A and 2-RB-50B) open during chemical addition evolutions is acceptable since these normally closed valves are opened to add chemicals to the RBCCW and then closed as directed by normal operating procedures. Therefore, operation with these valves open does not affect OPERABILITY of the RBCCW loops.

Surveillance Requirement 4.7.3.1.a verifies the correct alignment for manual, power operated, and automatic valves in the RBCCW System flow paths to provide assurance that the proper flow paths exist for RBCCW operation. This surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

Surveillance Requirements 4.7.3.1.b and 4.7.3.1.c demonstrate that each automatic RBCCW valve actuates to the required position on an actual or simulated actuation signal and that each RBCCW pump starts on receipt of an actual or simulated actuation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

3/4.7.4 SERVICE WATER SYSTEM

The OPERABILITY of the Service Water (SW) System ensures that sufficient cooling capacity is available for continued operation of vital components and Engineered Safety Feature equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident analyses.

3/4.7.4 SERVICE WATER SYSTEM (Continued)

The SW loops are redundant of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a design basis accident, one SW loop is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two SW loops must be OPERABLE, and independent to the extent necessary to ensure that a single failure will not result in the unavailability of both SW loops. At least one SW loop will operate assuming the worst single active failure occurs following a design basis accident coincident with a loss of offsite power, or the worst single passive failure occurs post - loss of coolant accident long term cooling. System design is assumed to mitigate the single active failure. System design or operator action is assumed to mitigate the passive failure.

The SW System has numerous cross connection points between the redundant loops, with manual valve isolation capability. When these valves are opened, the two system loops are no longer independent. The loss of independence will result in one large SW loop. This may adversely impact the ability of the SW System to mitigate the design basis events if a single failure, active or passive, occurs. Opening the manual cross-connection valves during normal operation should be evaluated to ensure system stability, minimum component cooling flow requirements, and the ability to mitigate the design basis event coincident with a single failure are maintained. Continuous operation with cross-connection valves open is acceptable if the configuration has been evaluated and protection against a single failure can be demonstrated. (Several system configurations that have been evaluated and determined acceptable for continuous plant operation are identified below). If opening a cross-connection valve will result in a plant configuration that does not provide adequate protection against a single failure, the following guidance applies. If only the manual cross-connect valves have been opened, and the SW System is in a normal configuration otherwise, with all system equipment OPERABLE, one SW loop should be considered inoperable and the ACTION requirements of Technical Specification 3.7.4.1 applied. If the SW System is not in a normal configuration otherwise and/or not all equipment is OPERABLE, both SW loops should be considered inoperable and the ACTION requirements of Technical Specification 3.0.3 applied.

The loss of loop independence is equivalent to the situation where one loop is inoperable. If one loop is inoperable, the remaining OPERABLE loop will be able to meet all design basis accident functions, assuming an additional single failure does not occur. If the loops are not independent, the remaining single large OPERABLE loop will be able to meet all design basis accident functions, assuming a single failure does not occur. Operation in a plant configuration where protection against a single failure can not be shown is acceptable provided the time period in that configuration is limited to less then the Technical Specification specified allowed outage time. It is acceptable to operate in the off normal plant configurations identified in the ACTION requirements for the time periods specified due to the low probability of occurrence of a design basis event concurrent with a single failure during this limited time period. The allowed outage time for one inoperable SW loop provides an appropriate limit for continued operation with only one OPERABLE SW loop, and can be applied to a plant configuration where only loop independence has been compromised. The loop

3/4.7.4 SERVICE WATER SYSTEM (Continued)

determined to be inoperable should be the loop that results in the most adverse plant configuration with respect to the availability of accident mitigation equipment. Restoration of loop independence within the time constraints of the allowed outage time is required, or a plant shutdown is necessary.

It is acceptable to operate with the SW header supply valves to sodium hypochlorite (2-SW-84A and 2-SW-84B) and the SW header supply valves to the north and south filters (2-SW-298 and 2-SW-299) open. Protection against a single failure (active or passive after the initiation of post - loss of coolant accident long term cooling) with these valves open is provided by the flow restricting orifices contained in these lines. Therefore, operation with these valves open does not affect OPERABILITY of the SW loops.

Surveillance Requirement 4.7.4.1.a verifies the correct alignment for manual, power operated, and automatic valves in the Service Water (SW) System flow paths to provide assurance that the proper flow paths exist for SW operation. This surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This frequency has been shown to be acceptable through operating experience.

Surveillance Requirements 4.7.4.1.b and 4.7.4.1.c demonstrate that each automatic SW valve actuates to the required position on an actual or simulated actuation signal and that each SW pump starts on receipt of an actual or simulated actuation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month frequency is based on the need to perform these surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the surveillances were performed with the reactor at power. The 18 month frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

3/4.7.5 DELETED

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

The OPERABILITY of the Control Room Emergency Ventilation System ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all credible accident conditions.

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM (Continued)

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. For all postulated design basis accidents except a Fuel Handling Accident, the radiation exposure to personnel occupying the control room shall be 5 rem or less whole body consistent with the requirements of General Design Criteria 19 of Appendix "A," 10 CFR 50. For a Fuel Handling Accident, the radiation exposure to personnel occupying the control room shall be 5 rem TEDE or less consistent with the requirements of 10 CFR 50.67

The LCO is modified by a footnote allowing the control room boundary to be opened intermittently under administrative controls. For entry and exit through doors the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in constant communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated.

The control room radiological dose calculations use the conservative minimum acceptable flow of 2250 cfm based on the flowrate surveillance requirement of 2500 cfm ± 10%.

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM (Continued)

Currently there are some situations where the CREV System may not automatically start on an accident signal, without operator action. Under most situations, the emergency filtration fans will start and the CREV System will be in the accident lineup. However, a failure of a supply fan (F21A or B) or an exhaust fan (F31A or B), operator action will be required to return to a full train lineup. Also, if a single emergency bus does not power up for one train of the CREV System, the opposite train filter fan will automatically start, but the required supply and exhaust fans will not automatically start. Therefore, operator action is required to establish the whole train lineup. This action is specified in the Emergency Operating Procedures. The radiological dose calculations do not take credit for CREV System cleanup action until 10 minutes into the accident to allow for operator action.

When the CREV System is checked to shift to the recirculation mode of operation, this will be performed from the normal mode of operation, and from the smoke purge mode of operation.

With both control room emergency ventilation trains inoperable due to an inoperable control room boundary, the movement of irradiated fuel assemblies within the spent fuel pool must be immediately suspended. The control room boundary must be restored to OPERABLE status within 24 hours, or the unit must be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

If the control room boundary is inoperable in MODES 1, 2, 3, and 4, the control room emergency ventilation trains cannot perform their intended functions. ACTIONS must be taken to restore an OPERABLE control room boundary within 24 hours. During the period that the control room boundary is inoperable, appropriate compensatory measures (consistent with the intent of GDC 19) should be utilized to protect control room operators from potential hazards such as radioactive contamination, toxic chemicals, smoke, temperature and relative humidity, and physical security. Preplanned measures should be available to address these concerns for intentional and unintentional entry into this condition. The 24 hour allowed outage time is reasonable based on the low probability of a DBA occurring during this time period, and the use of compensatory measures. The 24 hour allowed outage time is a typically reasonable time to diagnose, plan, and possibly repair, and test most problems with the control room boundary.

Surveillance Requirement 4.7.6.1.c.1 dictates the test frequency, methods and acceptance criteria for the Control Room Emergency ventilation System trains (cleanup trains). These criteria all originate in the Regulatory Position sections of Regulatory Guide 1.52, Rev. 2, March 1978 as discussed below.

Section C.5.a requires a visual inspection of the cleanup system be made before the following tests, in accordance with the provisions of section 5 of ANSI N510-1975:

- in-place air flow distribution test
- DOP test
- activated carbon adsorber section leak test

Bases Change of 6-28-2005

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION SYSTEM (Continued)

Section C.5.c requires the in-place Dioctyl phthalate (DOP) test for HEPA filters to conform to section 10 of ANSI N510-1975. The HEPA filters should be tested in place (1) initially, (2) at least once per 18 months thereafter, and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. The testing is to confirm a penetration of less than 0.05%* at rated flow. A filtration system satisfying this criteria can be considered to warrant a 99% removal efficiency for particulates.

Section C.5.d requires the charcoal adsorber section to be leak tested with a gaseous halogenated hydrocarbon refrigerant, in accordance with section 12 of ANSI N510-1975 to ensure that bypass leakage through the adsorber section is less than 0.05%.** Adsorber leak testing should be conducted (1) initially, (2) at least once per 18 months thereafter, (3) following removal of an adsorber sample for laboratory testing if the integrity of the adsorber section is affected, and (4) following painting, fire, or chemical release in any ventilation zone communicating with the system.

The ACTION requirements to immediately suspend various activities (CORE ALTERATIONS, irradiated fuel movement, etc.) do not preclude completion of the movement of a component to a safe position.

Technical Specification 3.7.6.1 provides the OPERABILITY requirements for the Control Room Emergency Ventilation Trains. If a Control Room Emergency Ventilation Train emergency power source or normal power source becomes inoperable in MODES 1, 2, 3, or 4 the requirements of Technical Specification 3.0.5 apply in determining the OPERABILITY of the affected Control Room Emergency Ventilation Train. If a Control Room Emergency Ventilation Train emergency power source or normal power source becomes inoperable in MODES 5 or 6 the guidance provided by Note "**" of this specification applies in determining the OPERABILITY of the affected Control Room Emergency Ventilation Train. If a Control Room Emergency Ventilation Train emergency power source or normal power source becomes inoperable while not in MODES 1, 2, 3, 4, 5, or 6 the requirements of Technical Specification 3.0.5 apply in determining the OPERABILITY of the affected Control Room Emergency Ventilation Train.

---

* Means that the HEPA filter will allow passage of less than 0.05% of the test concentration injection at the filter inlet from a standard DOP concentration injection.

** Means that the charcoal adsorber sections will allow passage of less than 0.05% of the injected test concentration around the charcoal adsorber section.

3/4.7.7 DELETED

3/4.7.8 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.

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 Plant Operations 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 Guide 8.8 and 8.10. The addition or deletion of any hydraulic or mechanic 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 systems. Therefore, the required inspection interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an inspection. 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.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, or are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber.

The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber reliability, a representative sample of the installed snubbers will be tested during plant shutdowns at eighteen (18) month intervals. Observed failures of these sample snubbers shall require testing of additional units.

Hydraulic snubbers and mechanical snubbers may each be treated as a different entity for the above surveillance programs.

The service life of a snubber is evaluated 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. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

3/4.7.9 DELETED

3/4.7.10 DELETED

3/4.7.11 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink temperature ensure that sufficient cooling capacity is available to either,

1) provide normal cooldown of the facility, or 2) to mitigate the effects of accident conditions within acceptable limits.

The limitations on maximum temperature are based on a 30-day cooling water supply to safety related equipment without exceeding their design basis temperature.

Various indications are available to monitor the temperature of the ultimate heat sink (UHS). The following guidelines apply to ensure the UHS Technical Specification limit is not exceeded.

The control room indications are normally used to ensure compliance with this specification. Control room indications are acceptable because of the close correlation between control room indications and local Service Water System (SWS) header indications (historically within approximately 2°F). The highest reading valid temperature obtained from the Unit 2 intake structure and the inlets to the Circulating Water System water boxes shall be used to verify the UHS temperature limit of 75°F is not exceeded.

When the highest reading valid control room indication indicates the temperature of the UHS is > 70°F, local SWS header indications must be used. The highest reading valid local SWS header temperature shall be used to verify the UHS temperature limit of 75°F is not exceeded. Normally, local SWS header temperature will be taken at the inlet to the vital AC switchgear room cooling coils. If the local SWS header temperature cannot be taken at the inlet to the vital AC switchgear room cooling coils, the inlet to the Reactor Building Closed Cooling Water heater exchangers, or other acceptable instrumentation should be used to determine SWS header temperature.

If the UHS temperature exceeds 75°F, plant operations may continue provided the LCO recorded water temperastures, averaged over the previous 24 hour period, are at or below 75°F. This verification is required to be performed once per hour when the water temperatire exceeds 75°F. If the UHS temperature, averaged over the previous 24 hour period, exceeds the 75°F Technical Specification limit, or if the UHS temperature exceeds 77°F, a plant shutdown in accordance with the ACTION requirements will be necessary.

Bases Change of 6-28-2005

3/4.8 ELECTRICAL POWER SYSTEMS

BASES

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.

The required circuits between the offsite transmission network and the onsite Class 1E distribution system (Station Busses 24C, 24D, and 24E) that satisfy Technical Specification 3.8.1.1.a (MODES 1, 2, 3, and 4) consist of the following circuits from the switchyard to the onsite electrical distribution system:

a. Station safeguards busses 24C and 24D via the Unit 2 Reserve Station Service Transformer and bus 24G; and

b. Station bus 24E via the Unit 3 Reserve Station Service Transformer or Unit 3 Normal Station Service Transformer (energized with breaker 13T and associated disconnect switches open) and bus 34A or 34B.

If the plant configuration will not allow Unit 3 to supply power to Unit 2 from the Unit 3 Reserve Station Transformer or Unit 3 Normal Station Service within 3 hours, Unit 2 must consider the second offsite source inoperable and enter the appropriate ACTION statement of Technical Specification 3.8.1.1 for an inoperable offsite circuit.

This is consistent with the GDC 17 requirement for two offsite sources. Each offsite circuit is required to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. The first source is required to be available with in a few seconds to supply power to safety related equipment following a loss of coolant accident. The second source is not required to be available immediately and no accident is assumed to occur concurrently with the need to use the second source. However, the second source is required to be available in sufficient time to assure the reactor remains in a safe condition The 3 hour time period is based on the Millstone Unit No. 2 Appendix R analysis. This analysis has demonstrated that the reactor will remain in a safe condition (i.e., the pressurizer will not empty) if charging is restored within 3 hours.

In MODES 1 through 4 (Technical Specification 3.8.1.1), the Unit 2 Normal Station Service Transformer can be used as the second offsite source after the main generator disconnect links have been removed and the backfeed line up established.

The required circuit between the offsite transmission network and the onsite Class 1 E distribution system (Station Busses 24C, 24D, and 24E) that satisfies Technical Specification 3.8.1.2.a (MODES 5 and 6) consists of the following circuit from the switchyard to the onsite electrical distribution system:

a. Station safeguards bus 24C or 24D via the Unit 2 Reserve Station Service Transformer and bus 24G; or

b. Station safeguards bus 24C or 24D via the Unit 2 Normal Station Service Transformer and bus 24A or 24B after the main generator disconnect links have been removed and the backfeed lineup established; or

c. Station bus 24E via the Unit 3 Reserve Station Service Transformer or Unit 3 Normal Station Service Transformer (energized with breaker 13T and associated disconnect switches open) and bus 34A or 34B.

Bases Change of 6-28-2005

When the plant is operating with the main generator connected to the grid, the output of the main generator will normally be used to supply the onsite Class 1E distribution system. During this time the required offsite circuits will be in standby, ready to supply power to the onsite Class 1E distribution system if the main generator is not available. When shut down, only one of the offsite circuits will normally be used to supply the onsite Class 1E distribution system. The other offsite circuit, if required, will be in standby. Verification of the required offsite circuits consists of checking control power to the breakers (breaker indicating lights), proper breaker position for the current plant configuration, and voltage indication as appropriate for the current plant configuration.

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 one of each 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.

Technical Specification 3.8.1.1 ACTION Statements b and c provide an allowance to avoid unnecessary testing of the other OPERABLE diesel generator. If it can be determined that the cause of the inoperable diesel generator does not exist on the OPERABLE diesel generator, Surveillance Requirement 4.8.1.1.2.a.2 does not have to be performed. If the cause of inoperability exists on the other OPERABLE diesel generator, the other OPERABLE diesel generator would be declared inoperable upon discovery, ACTION Statement e would be entered, and appropriate ACTIONS will be taken. Once the failure is corrected, the common cause failure no longer exists, and the required ACTION Statements (b, c, and e) will be satisfied.

If it cannot be determined that the cause of the inoperable diesel generator does not exist on the remaining diesel generator, performance of Surveillance Requirement 4.8.1.1.2.a.2, within the allowed time period, suffices to provide assurance of continued OPERABILITY of the diesel generator. If the inoperable diesel generator is restored to OPERABLE status prior to the determination of the impact on the other diesel generator, evaluation will continue of the possible common cause failure. This continued evaluation is no longer under the time constraint imposed while in ACTION Statement b or c.

The determination of the existence of a common cause failure that would affect the remaining diesel generator will require an evaluation of the current failure and the applicability to the remaining diesel generator. Examples that would not be a common cause failure include, but are not limited to:

1. Preplanned preventive maintenance or testing, or

2. An inoperable support system with no potential common mode failure for the remaining diesel generator, or

Basis Change of 6-28-2005

3. An independently testable component with no potential common mode failure for the remaining diesel generator.

If one Millstone Unit No. 2 diesel generator is inoperable in MODES 1 though 4, ACTION Statements b.3 and c.3 require verification that the steam-driven auxiliary feedwater pump is OPERABLE (MODES 1, 2, and 3 only). If the steam-driven auxiliary feedwater pump is inoperable, restoration within 2 hours is required or a plant shutdown to MODE 4 will be necessary. This requirement is intended to provide assurance that a loss of offsite power event will not result in degradation of the auxiliary feedwater safety function to below accident mitigation requirements during the period one of the diesel generators is inoperable. The term verify, as used in this context, means to administratively check by examining logs or other information to determine if the steam-driven auxiliary feedwater pump is out of service for maintenance or other reasons. It does not mean to perform Surveillance Requirements needed to demonstrate the OPERABILITY of the steam-driven auxiliary feedwater pump.

If one Millstone Unit No. 2 diesel generator is inoperable in MODES 1 through 4, a 72 hour allowed outage time is provided by ACTION Statement b.5 to allow restoration of the diesel generator, provided the requirements of ACTION Statements b.1, b.2, and b.3 are met. This allowed outage time can be extended to 14 days if the additional requirements contained in ACTION Statement b.4 are also met. ACTION Statement b.4 requires verification that the Millstone Unit No. 3 diesel generators are OPERABLE as required by the applicable Millstone Unit No. 3 Technical Specification (2 diesel generators in MODES 1 through 4, and 1 diesel generator in MODES 5 and 6) and the Millstone Unit No. 3 SBO diesel generator is available. The term verify, as used in this context, means to administratively check by examining logs or other information to determine if the required Millstone Unit No. 3 diesel generators and the Millstone Unit No. 3 SBO diesel generator are out of service for maintenance or other reasons. It does not mean to perform Surveillance Requirements needed to demonstrate the OPERABILITY of the required Millstone Unit No. 3 diesel generators or availability of the Millstone Unit No. 3 SBO diesel generator.

When using the 14 day allowed outage time provision and the Millstone Unit No. 3 diesel generator and/or the Millstone Unit No. 3 SBO diesel generator requirements are not met, 72 hours is allowed for restoration of the required Millstone Unit No. 3 diesel generators and the Millstone Unit No. 3 SBO diesel generator. If any of the required Millstone Unit No. 3 diesel generators and/or the Millstone Unit No. 3 SBO diesel generator are not restored within 72 hours, and one Millstone Unit No. 2 diesel generator is still inoperable, Millstone Unit No. 2 is required to shut down.

Bases Change of 6-28-2005

The 14 day allowed outage time for one inoperable Millstone Unit No. 2 diesel generator will allow performance of extended diesel generator maintenance and repair activities (e.g., diesel inspections) while the plant is operating. To minimize plant risk when using this extended allowed outage time the following additional requirements must be met:

1. The extended diesel generator maintenance outage shall not be scheduled when adverse or inclement weather conditions and/or unstable grid conditions are predicted or present.

2. The availability of the Millstone Unit No. 3 SBO DG shall be verified by test performance within the previous 30 days prior to allowing a Millstone Unit No. 2 diesel generator to be inoperable for greater than 72 hours.

3. All activity in the switchyard shall be closely monitored and controlled. No elective maintenance within the switchyard that could challenge offsite power availability shall be scheduled.

In addition, the plant configuration shall be controlled during the diesel generator maintenance and repair activities to minimize plant risk consistent with a Configuration Risk Management Program, as required by 10 CFR 50.65(a)(4).

Diesel Generator Testing

An engine prelube period is allowed prior to engine start for all diesel generator testing. This will minimize wear on moving parts that do not get lubricated when the engine is not running.

When specified in the surveillance tests, the diesel generators must be started from a standby condition. Standby condition for a diesel generator means the diesel engine coolant and oil are being circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 4.8.1.1.2.a.2

This surveillance helps to ensure the availability of the standby electrical power supply to mitigate design basis accidents and transients and to maintain the unit in a safe shutdown condition. It verifies the ability of the diesel generator to start from a standby condition and achieve steady state voltage and frequency conditions. The time for voltage and speed (frequency) to stabilize is periodically monitored and the trend evaluated to identify degradation of governor or voltage regulator performance when testing in accordance with the requirements of the surveillance.

This surveillance is modified by two notes. Note 1 allows the use of a modified start based on recommendations of the manufacturer to reduce stress and wear on diesel engines. When using a modified start, the starting speed of the diesel generators is limited, warmup is limited to this lower speed, and the diesel generators are gradually accelerated to synchronous speed prior to loading. If a modified start is not used, the 15 second start requirement of SR 4.8.1.1.2.d applies. Note 2 states that SR 4.8.1.1.2.d, a more rigorous test, may be performed in lieu of 4.8.1.1.2.a.

During performance of SR 4.8.1.1.2.a.2, the diesel generator shall be started by using one of the following signals:

1. Manual;
2. Simulated loss of offsite power in conjunction with a safety injection actuation signal;
3. Simulated safety injection actuation signal alone; or
4. Simulated loss of power alone.

The 31 day frequency for SR 4.8.1.1.2.a.2 is consistent with standard industry guidelines.

SR 4.8.1.1.2.a.3

This surveillance verifies that the diesel generators are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the diesel generator is connected to the offsite source. Although no power factor requirements are established by this surveillance, the diesel generator is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation.

This surveillance is modified by five Notes. Note 1 indicates that diesel engine runs for this surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit will not invalidate the test. Note 3 indicates that this surveillance should be conducted on only one diesel generator at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this surveillance. A successful diesel generator start must precede this test to credit satisfactory performance. Note 5 states that SR 4.8.1.1.2.d, a more rigorous test, may be performed in lieu of 4.8.1.1.2.a.

The 31 day frequency for SR 4.8.1.1.2.a.3 is consistent with standard industry guidelines.

SR 4.8.1.1.2.b.1

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the three fuel storage tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. This surveillance is for preventative maintenance. The presence of water does not necessarily represent failure of this surveillance provided the accumulated water is removed during performance of the surveillance.

SR 4.8.1.1.2.b.2

This surveillance requires testing of the new and stored fuel oil in accordance with the Diesel Fuel Oil Testing Program, as defined in Section 6 of the Technical Specifications.

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows (more restrictive State of Connecticut and/or equipment limits may apply):

a. Sample the new fuel oil in accordance with ASTM D4057,

b. Verify in accordance with the tests specified in ASTM D975-81 that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89, or an API gravity at 60°F of ≥ 27° and ≤ 39°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes (alternatively, Saybolt viscosity, SUS at 100°F of ≥ 32.6 but ≤ 40.1) and a flash point ≥ 125°F, and

c. Verify that the new fuel oil has water and sediment ≤ 0.05% when tested in accordance with ASTM D1796-83.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks. Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-81 are met for new fuel oil when tested in accordance with ASTM D975-81, except that the analysis for sulfur may be performed in accordance with ASTM D1552 or ASTM D2622. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation.

This surveillance ensures the availability of high quality fuel oil for the diesel generators. Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure. Particulate concentrations should be determined in accordance with ASTM D2276-78, Method A, every 92 days. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between surveillance intervals.

SR 4.8.1.1.2.c.2

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the diesel generators due to high motor starting currents. The load sequence time interval tolerances ensure that sufficient time exists for the diesel generator to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding Engineered Safety Features (ESF) equipment time delays are not violated.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by a Note. The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, or 4 is further amplified to allow the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed surveillance, a successful surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and start up to determine that plant safety is maintained or enhanced when the surveillance is performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.

SR 4.8.1.3.2.c.3

Each diesel generator is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This surveillance demonstrates the diesel generator load response characteristics and capability to reject the largest single load without exceeding a predetermined frequency limit. The single largest load for each diesel generator is identified in the FSAR (Tables 8.3-2 and 8.3-3).

This surveillance may be accomplished by either:

a. Tripping the diesel generator output breaker with the diesel generator carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power or while solely supplying the bus; or

b. Tripping the equivalent of the single largest post-accident load with the diesel generator solely supplying the bus.

The time, voltage, and frequency tolerances specified in this surveillance are based on the response during load sequence intervals. The 2.2 seconds specified is equal to 40% of the 5.5 second load sequence interval associated with sequencing of the largest load (Safety Guide 9). The voltage and frequency specified are consistent with the design range of the equipment powered by the diesel generator. SR 4.8.1.1.2.c.3.a corresponds to the maximum frequency excursion, while SR 4.8.1.1.2.c.3.b and SR 4.8.1.1.2.c.3.c are steady state voltage and frequency values to which the system must recover following load rejection.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by a Note to ensure that the diesel generator is tested under load conditions that are as close to design basis conditions as practical. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.9 lagging. This power factor is representative of the inductive loading a diesel generator would see based on the motor rating of the single largest load. It is within the adjustment capability of the Control Room Operator based on the use of reactive load indication to establish the desired power factor. Under certain conditions, however, the note allows the surveillance to be conducted at a power factor other than ≤ 0.9. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.9 results in voltages on the emergency buses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.9 while still maintaining acceptable voltage limits on the emergency buses. In other circumstances, the grid voltage may be such that the diesel generator excitation levels needed to obtain a power factor of 0.9 may not cause unacceptable voltages on the emergency buses, but the excitation levels are in excess of those recommended for the diesel generator. In such cases, the power factor shall be maintained as close as practicable to 0.9 lagging without exceeding the diesel generator excitation limits.

SR 4.8.1.1.2.c.4

This surveillance demonstrates the diesel generator capability to reject a rated load without overspeed tripping. A diesel generator rated load rejection may occur because of a system fault or inadvertent breaker tripping. This surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the diesel generator experiences following a rated load rejection and verifies that the diesel generator will not trip upon loss of the load. While the diesel generator is not expected to experience this transient during an event, this response ensures that the diesel generator is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

This surveillance is performed by tripping the diesel generator output breaker with the diesel generator carrying the required load while paralleled to offsite power.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by a Note to ensure that the diesel generator is tested under load conditions that are as close to design basis conditions as practical. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.83 lagging. This power factor is representative of the inductive loading a diesel generator would see under design basis accident conditions. Under certain conditions, however, the note allows the surveillance to be conducted at a power factor other than ≤ 0.83. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.83 results in voltages on the emergency buses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.83 while still maintaining acceptable voltage limits on the emergency buses. In other circumstances, the grid voltage may be such that the diesel generator excitation levels needed to obtain a power factor of 0.83 may not cause unacceptable voltages on the emergency buses, but the excitation levels are in excess of those recommended for the diesel generator. In such cases, the power factor shall be maintained as close as practicable to 0.83 lagging without exceeding the diesel generator excitation limits.

SR 4.8.1.1.2.c.5

In the event of a design basis accident coincident with a loss of offsite power, the diesel generators are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. This surveillance demonstrates the diesel generator operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the diesel generator. It further demonstrates the capability of the diesel generator to automatically achieve the required voltage and speed (frequency) within the specified time. The diesel generator auto-start time of 15 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to verify the connection of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the diesel generator loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the diesel generator system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

For the purpose of this testing, the diesel generators must be started from a standby condition. Standby condition for a diesel generator means the diesel engine coolant and oil are being circulated and temperature is being maintained consistent with manufacturer recommendations.

This surveillance is modified by a Note. The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1 2, 3, or 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and start up to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for the assessment.

SR 4.8.1.1.2.c.6

This surveillance demonstrates that diesel generator noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. During this time, the critical protective functions (engine overspeed, generator differential current, low lube oil pressure [2 out of 3 logic], and voltage restraint overcurrent) remain available to trip the diesel generator and/or output breaker to avert substantial damage to the diesel generator unit. An EDG Emergency Start Signal (Loss of Power signal or SIAS) bypasses the EDG mechanical trips in the EDG control circuit, except engine overspeed, and switches the low lube oil trip to a 2 of 3 coincidence. The loss of power to the emergency bus, based on supply breaker position (A302, A304, and A505 for Bus 24C; A410, A411, and A505 for Bus 24D), bypasses the EDG electrical trips in the breaker control circuit except generator differential current and voltage restraint over current. The noncritical trips are bypassed during design basis accidents and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The diesel generator availability to mitigate the design basis accident is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the diesel generator.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by a Note. The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for the assessment.

SR 4.8.1.1.2.c.7

This surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the diesel generator. It further demonstrates the capability of the diesel generator to automatically achieve the required voltage and speed (frequency) within the specified time. The diesel generator auto-start time of 15 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved. The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the diesel generator loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the diesel generator system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by two Notes. The reason for Note 1 is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of the surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial surveillance, a successful partial surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and start up to determine that plant safety is maintained or enhanced when portions of the surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for the assessment.

Surveillance Note 2 specifies that the start of the diesel generator from a standby condition is not required if this surveillance is performed in conjunction with SR 4.8.1.1.2.c.5. Since this test is normally performed in conjunction with SR 4.8.1.1.2.c.5, the proposed note will exclude the requirement to start from a standby condition to minimize the time to perform this test. This will reduce shutdown risk since plant restoration, and subsequent equipment availability will occur sooner. In addition, it is not necessary to test the ability of the EDG to auto start from a standby condition for this test since that ability will have already been verified by SR 4.8.1.1.2.c.5, which will have just been performed if the note's exclusion is to be utilized. If this test is to be performed by itself, the EDG is required to start from a standby condition.

SR 4.8.1.1.2.c.8

This surveillance demonstrates that the diesel generator automatically starts and achieves the required voltage and speed (frequency) within the specified time (15 seconds) from the design basis actuation signal (Safety Injection Actuation Signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. Since the specified actuation signal (ESF signal without loss of offsite power) will not cause the emergency bus loads to be shed, and will not cause the diesel generator to load, the surveillance ensures that permanently connected loads and autoconnected loads remain energized from the offsite electrical power system (Unit 2 RSST or NSST, or Unit 3 RSST or NSST). In certain circumstances, many of these loads cannot actually be connected without undue hardship or potential for undesired operation. It is not necessary to verify all autoconnected loads remain connected. A representative sample is acceptable.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

For the purpose of this testing, the diesel generators must be started from a standby condition. Standby condition for a diesel generator means the diesel engine coolant and oil are being circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 4.8.1.1.2.c.9

This surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from a normal surveillance, and achieve the required voltage and speed within 15 seconds. The 15 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

The 18 month frequency is based on engineering judgment, taking into consideration unit conditions required to perform the surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the surveillance when performed at the 18 month frequency. Therefore, the frequency is acceptable from a reliability standpoint.

This surveillance is modified by a Note. The Note ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the diesel generator. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain diesel generator OPERABILITY. The requirement that the diesel has operated for at least 1 hour at rated load conditions prior to performance of this surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test.

SRs 4.8.1.1.2.d.1 and 4.8.1.1.2.d.2

SR 4.3.1.1.2.d.1 verifies that, at a 184 day frequency, the diesel generator starts from standby conditions and achieves required voltage and speed (frequency) within 15 seconds. The 15 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR. Diesel generator voltage and speed will continue to increase to rated values, and then should stabilize. SR 4.8.1.1.2.d.2 verifies the ability of the diesel generator to achieve steady state voltage and frequency conditions. The time for voltage and speed (frequency) to stabilize is periodically monitored and the trend evaluated to identify degradation of governor or voltage regulator performance when besting in accordance with the requirements of this surveillance.

The 184 day frequency for this surveillance is a reduction in cold testing consistent with Generic Letter 84-15. This frequency provides adequate assurance of diesel generator OPERABILITY, while minimizing degradation resulting from testing. In addition, SR 4.8.1.1.2.d may be performed in lieu of 4.8.1.1.2.a.

For the purpose of this testing, the diesel generators must be started from a standby condition. Standby condition for a diesel generator means the diesel engine coolant and oil are being circulated and temperature is being maintained consistent with manufacturer recommendations.

During performance of SR 4.8.1.1.2.d.1, the diesel generators shall be started by using one of the following signals:

1. Manual;
2. Simulated loss of offsite power in conjunction with a safety injection actuation signal;
3. Simulated safety injection actuation signal alone; or
4. Simulated loss of power alone.

SR 4.8.1.1.2.d.3

This surveillance verifies that the diesel generators are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the diesel generator is connected to the offsite source. Although no power factor requirements are established by this surveillance, the diesel generator is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation.

The 184 day frequency for this surveillance is a reduction in cold testing consistent with Generic Letter 84-15. This frequency provides adequate assurance of diesel generator OPERABILITY, while minimizing degradation resulting from testing.

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit will not invalidate the test. Note 3 indicates that this surveillance should be conducted on only one diesel generator at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this surveillance. A successful diesel generator start must precede this test to credit satisfactory performance.

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 facility status. If the required power sources or distribution systems are not OPERABLE in MODES 5 and 6, operations involving CORE ALTERATIONS, positive reactivity changes, or movement of irradiated fuel assemblies are required to be suspended. The required ACTION to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the boron concentration of the makeup water source is greater than or equal to the boron concentration for the required SHUTDOWN MARGIN. In addition, suspension of these activities does not preclude completion of actions to establish a safe conservative plant condition.

Each 125-volt D.C. bus train consists of its associated 125-volt D.C. bus, a 125-volt D.C. battery bank, and a battery charger with at least 400 ampere charging capacity. To demonstrate OPERABILITY of a 125-volt D.C. bus train, these components must be energized and capable of performing their required safety functions. Additionally, at least one tie breaker between the 125-volt D.C. bus trains must be open for a 125-volt D.C. bus train to be considered OPERABLE.

Footnote (a) to Technical Specification Tables 4.8-1 and 4.8-2 permits the electrolyte level to be above the specified maximum level for the Category A limits during equalizing charge, provided it is not overflowing. Because of the internal gas generation during the performance of an equalizing charge, specific gravity gradients and artificially elevated electrolyte levels are produced which may exist for several days following completion of the equalizing charge. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. In accordance with the recommendations of IEEE 450-1980, electrolyte level readings should be taken only after the battery has been at float charge for at least 72 hours.

Based on vendor recommendations and past operating experience, seven (7) days has been determined a reasonable time frame for the 125-volt D.C. batteries electrolyte level to stabilize and to provide sufficient time to verify battery electrolyte levels are with in the Category A limits.

Footnote (b) to Technical Specification Tables 4.8-1 and 4.8-2 requires that level correction is not required when battery charging current is < 5 amps on float charge. This current provides, in general, an indication of overall battery condition.

Bases Change of 6-28-2005

Footnote (c) to Technical Specification Tables 4.8-1 and 4.8-2 states that level correction is not required when battery charging current is < 5 amps on float charge. This current provides, in general, an indication of overall battery condition. Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity measurement for determining the state of charge. This footnote allows the float charge current to be used as an alternative to specific gravity to show OPERABILITY of a battery for up to seven (7) days following the completion of a battery equalizing charge. Each connected cells specific gravity must be measured prior to expiration of the 7 day allowance.

Surveillance Requirements 4.8.2.3.2.c.1 and 4.8.2.5.2.c.1 provide for visual inspection of the battery cells, cell plates, and battery racks to detect any indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The non-safety grade 125V D.C. Turbine Battery is required for accident mitigation for a main steam line break within containment with a coincident loss of a vital D.C. bus. The Turbine Battery provides the alternate source of power for Inverters 1 & 2 respectively via non-safety grade Inverters 5 & 6. For the loss of a D.C. event with a coincident steam line break within containment, the feedwater regulating valves are required to close to ensure containment design pressure is not exceeded.

The Turbine Battery D.C. electrical power subsystem consists of 125-volt D.C. bus 201D and 125-volt D.C. battery bank 201D. To demonstrate OPERABILITY of this subsystem, these components must be energized and capable of performing their required safety functions.

The feedwater regulating valves require power to close. On loss of a vital D.C. bus, the alternate source of power to the vital A.C. bus via the Turbine Battery ensures power is available to the affected feedwater regulating valve such that the valve will isolate feed flow into the faulted generator. The Turbine Battery is considered inoperable when bus voltage is less than 125 volts D.C, thereby ensuring adequate capacity for isolation functions via the feedwater regulating valves during the onset of a steam line break.

The Turbine Battery Charger is not required to be included in Technical Specifications even though the Turbine Battery is needed to power backup Inverters 5 & 6 for a main steam line break inside containment coincident with a loss of a Class 1E D.C. bus. This is due to the fact that feedwater isolation occurs within seconds from the onset of the event.

3/4.9 REFUELING OPERATIONS

The ACTION requirements to immediately suspend various activities (CORE ALTERATIONS, fuel movement, CEA movement, etc.) do not preclude completion of the movement of a component to a safe position.

3/4.9.1 BORON CONCENTRATION

The limitations on reactivity conditions during REFUELING ensure that: 1) the reactor will remain subcritical during CORE ALTERATIONS, and 2) sufficient boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel. These limitations are consistent with the initial conditions assumed for the boron dilution incident in the accident analyses. Reactivity control in the water volume having direct access to the reactor vessel is achieved by determining boron concentration in the refueling canal. The refueling canal is defined as the entire length of pool stretching from refuel pool through transfer canal to spent fuel pool.

The applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling canal when this volume is connected to the Reactor Coolant System (RCS). When the refueling canal is isolated from the RCS, no potential path for boron dilution exists. Prior to re-connecting portions of the refueling canal to the RCS, Surveillance 4.9.1.2 must be met. If any dilution activity has occurred while the refueling canal was disconnected from the RCS, this surveillance ensures the correct boron concentration prior to communication with the RCS.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of the source range neutron flux monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 DECAY TIME

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel 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.

3/4.9.4 CONTAINMENT PENETRATIONS

The requirements on containment penetration closure and OPERABILITY ensure that a release of radioactive material within containment to the environment will be minimized. The OPERABILITY, closure restrictions, and administrative controls are sufficient to minimize the release of radioactive material from a fuel element rupture based upon the lack of containment pressurization potential during the movement of irradiated fuel assemblies within containment. The containment purge valves are containment penetrations and must satisfy all requirements specified for a containment penetration.

Containment penetrations, including the personnel airlock doors and equipment door, can be open during the movement of irradiated fuel provided that sufficient administrative controls are in place such that any of these containment penetrations can be closed within 30 minutes. Following a Fuel Handling Accident, each penetration, including the equipment door, is closed such that a containment atmosphere boundary can be established. However, if it is determined that closure of all containment penetrations would represent a significant radiological hazard to the personnel involved, the decision may be made to forgo the closure of the affected penetration(s). The containment atmosphere boundary is established when any penetration which provides direct access to the outside atmosphere is closed such that at least one barrier between the containment atmosphere and the outside atmosphere is established. Additional actions beyond establishing the containment atmosphere boundary, such as installing flange bolts for the equipment door or a containment penetration, are not necessary.

Administrative controls for opening a containment penetration require that one or more designated persons, as needed, be available for isolation of containment from the outside atmosphere. Procedural controls are also in place to ensure cables or hoses which pass through a containment opening can be quickly removed. The location of each cable and hoses isolation device for those cables and hoses which pass through a containment opening is recorded to ensure timely closure of the containment boundary. Additionally, a closure plan is developed for each containment opening which includes an estimated time to close the containment opening. A log of personnel designated for containment closure is maintained, including identification of which containment openings each person has responsibility for closing. As necessary, equipment will be pre-staged to support timely closure of a containment penetration.

3/4.9.4 CONTAINMENT PENETRATIONS (Continued)

Prior to opening a containment penetration, a review of containment penetrations currently open is performed to verify that sufficient personnel are designated such that all containment penetrations can be closed within 30 minutes. Designated personnel may have other duties, however, they must be available such that their assigned containment openings can be closed within 30 minutes. Additionally, each new work activity inside containment is reviewed to consider its effect on the closure of the equipment door, personnel air lock, and/or other open containment penetrations. The required number of designated personnel are continuously available to perform closure of their assigned containment openings whenever irradiated fuel is being moved within the containment.

Administrative controls are also in place to ensure that the containment atmosphere boundary is established if adverse weather conditions which could present a potential missile hazard threaten the plant. Weather conditions are monitored during irradiated fuel movement whenever a containment penetration, including the equipment door and personnel air lock, is open and a storm center is within the plant monitoring radius of 150 miles.

The administrative controls ensure that the containment atmosphere boundary can be quickly established (i.e., within 30 minutes) upon determining that adverse weather conditions exist which pose a significant threat to the Millstone Site. A significant threat exists when a hurricane warning or tornado warning is issued which applies to the Millstone Site, or if an average wind speed of 60 miles an hour or greater is recorded by plant meteorological equipment at the meteorological tower. If the meteorological equipment is inoperable, information from the National Weather Service can be used as a backup in determining plant wind speeds. Closure of containment penetrations, including the equipment door and personnel air lock door, begin immediately upon determination that a significant threat exists.

When severe weather conditions which could generate a missile are within the plant monitoring radius, containment and spent fuel pool penetrations are closed to establish the containment atmosphere boundary.

3/4.9.5 DELETED

3/4.9.6 DELETED

3/4.9.7 DELETED

3/4.9.8 SHUTDOWN COOLING AND COOLANT CIRCULATION

In MODE 6, the shutdown cooling (SDC) trains are the primary means of heat removal. One SDC train provides sufficient heat removal capability. However, to provide redundant paths for decay heat removal either two SDC trains are required to be OPERABLE and one SDC train must be in operation, or one SDC train is required to be OPERABLE and in operation with the refueling cavity water level $\geq$ 23 feet above the reactor vessel flange. This volume of water in the refueling cavity will provide a large heat sink in the event of a failure of the operating SDC train. Any exceptions to these requirements are contained in the LCO Notes.

An OPERABLE SDC train, for plant operation in MODE 6, includes a pump, heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine RCS temperature. In addition, sufficient portions of the Reactor Building Closed Cooling Water (RBCCW) and Service Water (SW) Systems shall be OPERABLE as required to provide cooling to the SDC heat exchanger. The flow path starts at the RCS hot leg and is returned to the RCS cold legs. An OPERABLE SDC train consists of the following equipment:

1. An OPERABLE SDC pump (low pressure safety injection pump);
2. The associated SDC heat exchanger from the same facility as the SDC pump;
3. An RBCCW pump, powered from the same facility as the SDC pump, and RBCCW heat exchanger capable of cooling the associated SDC heat exchanger;
4. A SW pump, powered from the same facility as the SDC pump, capable of supplying cooling water to the associated RBCCW heat exchanger; and
5. All valves required to support SDC System operation are in the required position or are capable of being placed in the required position.

In MODE 6, two OPERABLE SDC trains require 2 SDC pumps, 2 SDC heat exchangers, 2 RBCCW pumps, 2 RBCCW heat exchangers, and 2 SW pumps. In addition, 2 RBCCW headers are required to provide cooling to the SDC heat exchangers, but only 1 SW header is required to support the SDC trains. The equipment specified is sufficient to address a single active failure of the SDC System and associated support systems.

Either SDC pump may be aligned to the refueling water storage tank (RWST) to support filling the refueling cavity or for performance of required testing. A SDC pump may also be used to transfer water from the refueling cavity to the RWST. In addition, either SDC pump may be aligned to draw a suction on the spent fuel pool (SFP) through 2-RW-11 and 2-SI-442 instead of the normal SDC suction flow path, provided the SFP transfer canal gate valve 2-RW-280 is open under administrative control (e.g., caution tagged). When using this alternate SDC flow path, it will be necessary to secure the SFP cooling pumps, and limit SDC flow as specified in the appropriate procedure, to prevent vortexing in the suction piping. The evaluation of this alternate SDC flow path assumed that this flow path will not be used during a refueling outage until after the completion of the fuel shuffle such that approximately one third of the reactor core will contain new fuel. By waiting until

Brian Chame

3/4.9.8 SHUTDOWN COOLING AND COOLANT CIRCULATION (Continued)

a refueling outage until after the completion of the fuel shuffle such that approximately one third of the reactor core will contain new fuel. By waiting until the completion of the fuel shuffle, sufficient time (at least 14 days from reactor shutdown) will have elapsed to ensure the limited SDC flow rate specified for this alternate lineup will be adequate for decay heat removal from the reactor core and the spent fuel pool. In addition, CORE ALTERATIONS shall be suspended when using this alternate flow path, and this flow path should only be used for short time periods, approximately 12 hours. If the alternate flow path is expected to be used for greater than 24 hours, or the decay heat load will not be bounded as previously discussed, further evaluation is required to ensure that this alternate flow path is acceptable.

These alternate lineups do not affect the OPERABILITY of the SDC train. In addition, these alternate lineups will satisfy the requirement for a SDC train to be in operation if the minimum required SDC flow through the reactor core is maintained.

In MODE 6, with the refueling cavity filled to ≥ 23 feet above the reactor vessel flange, both SDC trains may not be in operation for up to 1 hour in each 8 hour period, provided no operations are permitted that would cause a reduction in RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles, and RCS to SDC isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling pool.

In MODE 6, with the refueling cavity filled to ≥ 23 feet above the reactor vessel flange, both SDC trains may also not be in operation for local leak rate testing of the SDC cooling suction line (containment penetration number 10) or to permit maintenance on valves located in the common SDC suction line. This will allow the performance of required maintenance and testing that otherwise may require a full core offload. In addition to the requirement prohibiting operations that would cause a reduction in RCS boron concentration, CORE ALTERATIONS are suspended and all containment penetrations providing direct access from the containment atmosphere to outside atmosphere must be closed. The containment purge valves are containment penetrations and must satisfy all requirements specified for a containment penetration. No time limit is specified to operate in this configuration. However, factors such as scope of the work, decay heat load/heatup rate, and RCS temperature should be considered to determine if it is feasible to perform the work. Prior to using this provision, a review and approval of the evolution by the SORC is required. This review will evaluate current plant conditions and the proposed work to determine if this provision should be used, and to establish the termination criteria and appropriate contingency plans. During this period, decay heat is removed by natural convection to the large mass of water in the refueling pool.

The requirement that at least one shutdown cooling loop be in operation at ≥ 1000 gpm 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 the REFUELING MODE, (2) sufficient coolant circulation is maintained through the reactor core to minimize the effects of a boron dilution incident and prevent boron stratification, and (3) is consistent with boron

3/4.9.8 SHUTDOWN COOLING AND COOLANT CIRCULATION (Continued)

Average Coolant Temperature (T_{avg}) values are derived under shutdown cooling conditions, using the designated formula for use in Unit 2 operating procedures.

- SDC flow greater than 1000 gpm: $(SDC_{outlet} + SDC_{inlet}) / 2 = T_{avg}$

During SDC only operation, there is no significant flow past the loop RTDs. Core inlet and outlet temperatures are accurately measured during those conditions by using T351Y, SDC return to RCS temperature indication, and T351X, RCS to SDC temperature indication. The average of these two indicators provides a temperature that is equivalent to the average RCS temperature in the core.

T351X will not be available when using the alternate SDC suction flow path from the SFP. Substitute temperature monitoring capability shall be established to provide indication of reactor core outlet temperature. A portable temperature device can be used to indicate reactor core outlet temperature. Indication of reactor core outlet temperature from this temporary device shall be readily available to the control room personnel. A remote television camera or an assigned individual are acceptable alternative methods to provide this indication to control room personnel.

3/4.9.9 and 3/4.9.10 DELETED

3/4.9.11 and 3/4.9.12 WATER LEVEL-REACTOR VESSEL AND STORAGE POOL WATER LEVEL

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. The minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.13 DELETED

3/4.9.14 DELETED

3/4.9.15 DELETED

THIS PAGE INTENTIONALLY LEFT BLANK

3/4.9.16 SHIELDED CASK

The limitations of this specification and 3/4.9.15 ensure that in the event of a shielded cask drop accident the doses from ruptured fuel assemblies will be within the assumptions of the safety analyses.

3/4.9.17 SPENT FUEL POOL BORON CONCENTRATION

The limitations of this specification ensures that sufficient boron is present to maintain spent fuel pool $K_{eff} \leq 0.95$ under accident conditions.

Postulated accident conditions which could cause an increase in spent fuel pool reactivity are: a single dropped or mis-loaded fuel assembly, a single dropped or mis-loaded Consolidated Fuel Storage Box, or a shielded cask drop onto the storage racks. A spent fuel pool soluble boron concentration of 1400 ppm is sufficient to ensure $K_{eff} \leq 0.95$ under these postulated accident conditions. The required spent fuel pool soluble boron concentration of ≥ 1720 ppm conservatively bounds the required 1400 ppm. The ACTION statement ensure that if the soluble boron concentration falls below the required amount, that fuel movement or shielded cask movement is stopped, until the boron concentration is restored to within limits.

An additional basis of this LCO is to establish 1720 ppm as the minimum spent fuel pool soluble boron concentration which is sufficient to ensure that the design basis value of 600 ppm soluble boron is not reached due to a postulated spent fuel pool boron dilution event. As part of the spent fuel pool criticality design, a spent fuel soluble boron concentration of 600 ppm is sufficient to ensure $K_{eff} \leq 0.95$, provided all fuel is stored consistent with LCO requirements. By maintaining the spent fuel pool soluble boron concentration ≥ 1720 ppm, sufficient time is provided to allow the operators to detect a boron dilution event, and terminate the event, prior to the spent fuel pool being diluted below 600 ppm. In the unlikely event that the spent fuel pool soluble boron concentration is decreased to 0 ppm, K_{eff} will be maintained <1.00, provided all fuel is stored consistent with LCO requirements. The ACTION statement ensures that if the soluble boron concentration falls below the required amount, that immediate action is taken to restore the soluble boron concentration to within limits, and that fuel movement or shielded cask movement is stopped. Fuel movement and shielded cask movement is stopped to prevent the possibility of creating an accident condition at the same time that the minimum soluble boron is below limits for a potential boron dilution event.

The surveillance of the spent fuel pool boron concentration within 24 hours of fuel movement, consolidated fuel movement, or cask movement over the cask layout area, verifies that the boron concentration is within limits just prior to the movement. The 7 day surveillance interval frequency is sufficient since no deliberate major replenishment of pool water is expected to take place over this short period of time.

3/4.9.18 SPENT FUEL POOL - STORAGE

The limitations described by Figures 3.9-1a, 3.9-1b, and 3.9-3 ensure that the reactivity of fuel assemblies and consolidated fuel storage boxes, introduced into the Region C spent fuel racks, are conservatively within the assumptions of the safety analysis.

The limitations described by Figure 3.9-4 ensure that the reactivity of the fuel assemblies, introduced into the Region A spent fuel racks, are conservatively within the assumptions of the safety analysis.

3/4.9.19 SPENT FUEL POOL - STORAGE PATTERN

The limitations of this specification ensure that the reactivity condition of the Region B storage racks and spent fuel pool K_{eff} will remain less than or equal to 0.95.

The Cell Blocking Devices in the 4th location of the Region B storage racks are designed to prevent inadvertent placement and/or storage in the blocked locations. The blocked location remains empty, or a Batch B fuel assembly may be stored in the blocked location, to maintain reactivity control for fuel assembly storage in any adjacent locations. Region B (non-cell blocker locations) is designed for the storage of new assemblies in the spent fuel pool, and for fuel assemblies which have not sustained sufficient burnup to be stored in Region A or Region C.

This LCO is not applicable during the initial installation of Batch B fuel assemblies in the cell blocker locations of Region B. This is acceptable because only Batch B fuel assemblies will be moved during the initial installation of Batch B fuel assemblies under the Region B cell blockers. Batch B fuel assemblies are qualified for storage in any spent fuel pool storage rack location, hence a fuel misloading event which causes a reactivity consequence is not credible. This exception is valid only during the initial installation of Batch B fuel assemblies in the cell blocker locations.

3/4.9.20 SPENT FUEL POOL - CONSOLIDATION

The limitations of these specifications ensure that the decay heat rates and radioactive inventory of the candidate fuel assemblies for consolidation are conservatively within the assumptions of the safety analysis.

BASES

3/4.10.1 SHUTDOWN MARGIN

This special test exception provides that a minimum amount of CEA worth is immediately available for reactivity control or that the reactor is sufficiently subcritical so as to provide safe operating conditions when tests are performed for CEA worth measurement. This special test exception is required to permit the periodic verification of the actual versus predicted core reactivity condition occuring as a result of fuel burnup or fuel cycling operations.

3/4.10.2 GROUP HEIGHT AND INSERTION LIMITS

This special test exception permits individual CEAs to be positioned outside of their normal group heights and insertion limits during the performance of such PHYSICS TESTS as those required to 1) measure CEA worth and 2) determine the reactor stability index and damping factor under xenon oscillation conditions.

3/4.11 DELETED

BASES

3/4.11.1 - DELETED

3/4.11.2 - DELETED

3/4.11.3 - DELETED

This page intentionally left blank

This page intentionally left blank

This page intentionally left blank

SECTION 5.0

DESIGN FEATURES

5.0 DESIGN FEATURES

5.1 SITE LOCATION

The Unit 2 Containment Building is located on the site at Millstone Point in Waterford, Connecticut. The nearest site boundary on land is 2034 feet northeast of the containment building wall (1627 feet northeast of the elevated stack), which is the minimum distance to the boundary of the exclusion area as described in 10 CFR 100.3. No part of the site that is closer than these distances shall be sold or leased except to Dominion Nuclear Connecticut, Inc. or its corporate affiliates for use in conjunction with normal utility operations.

5.2 DELETED

THIS PAGE INTENTIONALLY LEFT BLANK

THIS PAGE INTENTIONALLY LEFT BLANK

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 217 fuel assemblies with each fuel assembly containing 176 rods. Reload fuel shall be similar in physical design to the initial core loading and shall have a minimum nominal average enrichment of 4.85 weight percent of U-235. A fuel rod shall have a maximum enrichment of 5.0 weight percent of U-235.

CONTROL ELEMENT ASSEMBLIES

5.3.2 The reactor core shall contain 73 control element assemblies. The control element assemblies shall be designed and maintained in accordance with the design provisions contained in Section 3.0 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

5.4 DELETED

5.5 DELETED

5.6 FUEL STORAGE

CRITICALITY

5.6.1 a) The new fuel (dry) storage racks are designed and shall be maintained with sufficient center to center distance between assemblies to ensure a $k_{eff} \leq .95$. The maximum nominal average fuel assembly enrichment to be stored in these racks is 4.85 weight percent U-235. The maximum fuel rod enrichment to be stored in these racks is 5.0 weight percent U-235.

b) The spent fuel storage racks are designed and shall be maintained with fuel assemblies having a maximum nominal average enrichment of 4.85 weight percent U-235. The maximum fuel rod enrichment to be stored in these racks is 5.0 weight percent U-235.

c) The spent fuel storage racks are designed and shall be maintained with $K_{eff} < 1.00$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Westinghouse Report A-MP-FE-0011, Revision 1, "Millstone Unit 2 Spent Fuel Pool Criticality Analysis with Soluble Boron Credit."

d) The spent fuel storage racks are designed and shall be maintained with $K_{eff} \leq .95$ if fully flooded with water borated to 600 ppm, which includes an allowance for uncertainties as described in Westinghouse Report A-MP-FE-0011, Revision 1, "Millstone Unit 2 Spent Fuel Pool Criticality Analysis with Soluble Boron Credit."

e) Region A of the spent fuel storage pool is designed and shall be maintained with a nominal 9.8 inch center to center distance between storage locations. Fuel assemblies stored in this region must comply with Figure 3.9-4 to ensure that the design burnup has been sustained.

f) Region B of the spent fuel storage pool is designed and shall be maintained with a nominal 9.8 inch center to center distance between storage locations. Region B contains both blocked and un-blocked storage locations, shown in Figure 3.9-2. Fuel having a maximum nominal enrichment of 4.85 weight percent U-235, may be stored in un-blocked locations. Fuel stored in blocked locations must be Batch B fuel assemblies.

g) Region C of the spent fuel storage pool is designed and shall be maintained with a 9.0 inch center to center distance between storage locations. Fuel assemblies stored in this region must comply with Figures 3.9-1a or 3.9-1b to ensure that the design burn-up has been sustained. Additionally, fuel assemblies utilizing Figure 3.9-1b require that borated stainless steel poison pins are installed in the fuel assembly's center guide tube and in two diagonally opposite guide tubes. The poison pins are solid 0.87 inch O.D. borated stainless steel, with a boron content of 2 weight percent boron.

h) Region C of the spent fuel storage pool is designed to permit storage of consolidated fuel. The contents of the consolidated fuel storage boxes to be stored in this region must comply with Figure 3.9-3 to ensure that the design burnup has been sustained.

DESIGN FEATURES

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 22'6".

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 224 storage locations in Region A, 160 storage locations in Region B and 962 storage locations in Region C for a total of 1346 storage locations.

5.7 DELETED

5.8 DELETED

5.9 DELETED

SECTION 6.0

ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The designated officer shall be responsible for overall operation of the Millstone Station Site and shall delegate in writing the succession to this responsibility. The designated manager shall be responsible for overall Unit safe operation and shall delegate in writing the succession to this responsibility.

6.1.2 The Shift Manager shall be responsible for the control room command function.

6.1.3 Unless otherwise defined, the technical specification titles for members of the staff are generic titles. Unit specific titles for the functions and responsibilities associated with these generic titles are identified in appropriate administrative documents.

6.2 ORGANIZATION

6.2.1 OFFSITE AND ONSITE ORGANIZATIONS

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be established and defined for the higher management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Quality Assurance Program Topical Report.

b. The designated manager shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. The designated officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operation, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff and those who carry out radiation protection and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

6.2.2 FACILITY STAFF

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1.

6.2.2 FACILITY STAFF (Continued)

b. At least one licensed Operator shall be in the control room when fuel is in the reactor.

c. At least two licensed Operators shall be present in the control room during reactor start-up, scheduled reactor shutdown and during recovery from reactor trips.

FACILITY STAFF (CONTINUED)

d. A radiation protection technician shall be on site when fuel is in the reactor. (Table 6.2-1)

e. ALL CORE ALTERATIONS after the initial fuel loading shall be 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.

f. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions. These procedures should follow the general guidance of the NRC Policy Statement on working hours (Generic Letter No. 82-12).

6.3 FACILITY STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971* for comparable positions. Exceptions to this requirement are specified in the Quality Assurance Program.

6.3.2 If the operations manager does not hold a senior reactor operator license for Millstone Unit No. 2, then the operations manager shall have held a senior reactor operator license at a Pressurized Water Reactor and an individual serving in the capacity of the assistant operations manager shall hold a senior reactor operator license for Millstone Unit No. 2.

* As of November 1, 2001, applicants for reactor operator and senior reactor operator qualification shall meet or exceed the education and experience guidelines of Regulatory Guide 1.8, Revision 3, May 2000.

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE 6.2-1[3]

MINIMUM SHIFT-CREW COMPOSITION[2]

LICENSE CATEGORY	APPLICABLE MODES 1, 2, 3 & 4	5 & 6
Senior Reactor Operator	2	1[1]
Reactor Operator	2	1
Non-Licensed Operator	2	1
Shift Technical Advisor	1[4]	None Required

(1) Does not include the licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling individual supervising CORE ALTERATIONS after the initial fuel loading.

(2) The above shift crew composition and the qualified radiation protection technician of Section 6.2.2 may be less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence provided expeditious actions are taken to fill the required position.

(3) Requirements for minimum number of licensed operators on shift during operation in modes other than cold shutdown or refueling are contained in 10CFR50.54(m).

(4) The Shift Technical Advisor position can be filled by either of the two Senior Reactor Operators (a dual-role individual), if he meets the Shift Technical Advisor qualifications of the Commission Policy Statement on Engineering Expertise on Shift.

6.4 TRAINING

A retraining and replacement training program for the facility staff that meets or exceeds the requirements as specified in the Quality Assurance Program and 10 CFR Part 55.59 shall be maintained.

6.5 Deleted.

PAGES 6-6 THROUGH 6-13 HAVE BEEN INTENTIONALLY DELETED.

6.6 Deleted.

6.7 Deleted.

6.8 PROCEDURES

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, February, 1978.

b. Refueling operations.

c. Surveillance activities of safety related equipment..

d. Not used.

e. Not used.

f. Fire Protection Program implementation.

g. Quality Control for effluent monitoring using the guidance in Regulatory Guide 1.21 Rev. 1, June 1974.

h. Radiological Effluent Monitoring and Offsite Dose Calculation Manual (REMODCM) implementation, except for Section I.E., Radiological Environmental Monitoring.

6.8.2 a. The designated manager or designated officer or designated senior officer may designate specific procedures and programs, or classes of procedures and programs to be reviewed in accordance with the Quality Assurance Program Topical Report.

b. Procedures and programs listed in Specification 6.8.1, and changes thereto, shall be approved by the designated manager or designated officer or by cognizant managers or directors who are designated as the Approval Authority by the designated manager or designated officer, as specified in administrative procedures. The Approval Authority for each procedure and program or class of procedure and program shall be specified in administrative procedures.

c. Each procedure of Specification 6.8.1, and changes thereto, shall be reviewed and approved in accordance with the Quality Assurance Program Topical Report, prior to implementation. Each procedure of Specification 6.8.1 shall be reviewed periodically as set forth in administrative procedures.

6.8.3 Temporary changes to procedures of 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered.

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License on the unit affected.

c. The change is documented, reviewed and approved in accordance with the Quality Assurance Program Topical Report within 14 days of implementation.

6.8.4 Written procedures shall be established, implemented and maintained covering Section I.E, Radiological Environmental Monitoring, of the REMODCM.

6.8.5 All procedures and procedure changes required for the Radiological Environmental Monitoring Program (REMP) of 6.8.4 above shall be reviewed by an individual (other than the author) from the organization responsible for the REMP and approved by appropriate supervision.

Temporary changes may be made provided the intent of the original procedure is not altered and the change is documented and reviewed by an individual (other than the author) from the organization responsible for the REMP within 14 days of implementation.

6.9 REPORTING REQUIREMENTS

Routine Reports

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 U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, one copy to the Regional Administrator, Region I, and one copy to the NRC Resident Inspector, unless otherwise noted.

Startup Report

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 plant.

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 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 power 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 in accordance with 10 CFR 50.4

6.9.1.5a.DELETED

6.9.1.5b The complete results of steam generator tube inservice inspections performed during the report period (reference Specification 4.4.5.1.5.b). The report covering the previous calendar year shall be submitted prior to March 1 of each year.

6.9.1.5c. The results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.4.8. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit. The report covering the previous calendar year shall be submitted prior to March 1 of each year.

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.

ANNUAL RADIOLOGICAL REPORTS

6.9.1.6a ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT

------------------------------------ NOTE ------------------------------------

A single submittal may be made for a multiple unit station. The submittal shall combine sections common to all units at the station

----

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in the Radiological Effluent Monitoring and Offsite Dose Calculation Manual (REMODCM), and in 10 CFR Part 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the REMODCM, as well as summarized and tabulated results of these analyses and measurements. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in the next annual report.

6.9.1.6b RADIOACTIVE EFFLUENT RELEASE REPORT

------------------------------------ NOTE ------------------------------------

A single submittal may be made for a multiple unit station. The submittal shall combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit in the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the REMODCM and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I , Section IV.B.I.

6.9.1.7 Deleted

CORE OPERATING LIMITS REPORT

6.9.1.8 a. Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle.

3/4.1.1.1	SHUTDOWN MARGIN (SDM)
3/4.1.1.4	Moderator Temperature Coefficient
3/4.1.3.6	Regulating CEA Insertion Limits
3/4.2.1	Linear Heat Rate
3/4.2.3	Total Integrated Radial Peaking Factor - F^T_r
3/4.2.6	DNB Margin

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1) EMF-96-029(P)(A) Volumes 1 and 2, "Reactor Analysis System for PWRs Volume 1 - Methodology Description, Volume 2 -Benchmarking Results," Siemens Power Corporation.

2) ANF-84-73 Appendix B (P)(A), "Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events," Advanced Nuclear Fuels.

3) XN-NF-82-21(P)(A), "Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations," Exxon Nuclear Company.

4) XN-75-32(P)(A) Supplements 1 through 4, "Computational Procedure for Evaluating Fuel Rod Bowing," Exxon Nuclear Company.

5) EFN-2328(P)(A), "PWR Small Break LOCA Evaluation Model S-RELAP5 Based," Framatome ANP.

6) EMF-2087(P)(A), "SEM/PWR-98: ECCS Evaluation Model for PWR LBLOCA Applications," Siemens Power Corporation.

7) XN-NF-44(NP)(A), "A Generic Analysis of the Control rod Ejection Transient for Pressurized water reactors," Exxon Nuclear Company.

CORE OPERATING LIMITS REPORT (CONT.)

8) XN-NF-621(P)(A), "Exxon Nuclear DNB Correlation for PWR Fuel Designs," Exxon Nuclear Company.

9) XN-NF-82-06(P)(A) and Supplements 2, 4, and 5, "Qualification of Exxon Nuclear Fuel for Extended Burnup," Exxon Nuclear Company.

10) ANF-88-133(P)(A) and Supplement 1, "Qualification of Advanced Nuclear Fuels PWR Design Methodology for Rod Burnups of 62 GWd/MTU," Advanced Nuclear Fuels Corporation.

11) XN-NF-85-92(P)(A), "Exxon Nuclear Uranium Dioxide/Gadolinia Irradiation Examination and Thermal Conductivity Results," Exxon Nuclear Company.

12) ANF-89-151(P)(A), "ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events," Advanced Nuclear Fuels Corporation.

13) EMF-1961(P)(A), "Statistical Setpoint/Transient Methodology for Combustion Engineering Type Reactors," Siemens Power Corporation.

14) EMF-2310(P)(A), "SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors," Framatome ANP.

15) EMF-92-153(P)(A) and Supplement 1, "HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel," Siemens Power Corporation.

c. The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met.

d. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555, one copy to the Regional Administrator, Region I, and one copy to the NRC Resident Inspector within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification:

a. Deleted

SPECIAL REPORTS (CONT.)

b. Deleted

c. Deleted

d. ECCS Actuation, Specifications 3.5.2 and 3.5.3.

e. Deleted

f. Deleted

g. RCS Overpressure Mitigation, Specification 3.4.9.3.

h. Deleted

i. Tendon Surveillance Report, Specification 6.25

j. Steam Generator Tube Inspection, Specification 4.4.5.1.5.

k. Accident Monitoring Instrumentation, Specification 3.3.3.8.

l. Radiation Monitoring Instrumentation, Specification 3.3.3.1.

m. Deleted

6.10 Deleted.

6.11 RADIATION PROTECTION PROGRAM

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

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

6.12.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of a Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

6.12 HIGH RADIATION AREA (CONT.)

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures from entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area, or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

6.12 HIGH RADIATION AREA (CONT.)

6.12.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the shift manager, radiation protection manager, or his or her designees, and

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

6.12 HIGH RADIATION AREA (CONT.)

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate, nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

6.13 SYSTEMS INTEGRITY

The licensee shall implement a program to reduce leakage from systems outside containment that would, or could, contain highly radioactive fluids during a serious transient, or accident, to as low as practical levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

6.14 IODINE MONITORING

The licensee shall implement 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.

6.15 RADIOLOGICAL EFFLUENT MONITORING AND OFFSITE DOSE CALCULATION MANUAL (REMODCM)

a. The REMODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The REMODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release, reports required by Specification 6.9.1.6a and Specification 6.9.1.6b.

Licensee initiated changes to the REMODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1) sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   2) a determination that the change(s) will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I of 10 CFR 50, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after review and acceptance by SORC and the approval of the designated officer; and

c. Shall be submitted to the Commission in the form of a complete, legible copy of the entire REMODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the REMODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

6.16 RADIOACTIVE WASTE TREATMENT

Procedures for liquid and gaseous radioactive effluent discharges from the Unit shall be prepared, approved, maintained, and adhered to for all operations involving offsite releases of radioactive effluents. These procedures shall specify the use of appropriate* waste treatment utilizing the guidance provided in the REMODCM.

6.17 SECONDARY WATER CHEMISTRY

A program shall be maintained for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

1. Identification of a sampling schedule for the critical variables and control points for these variables.
2. Identification of the procedures used to measure the values of the critical variables,
3. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in-leakage.
4. Procedures for the recording and management of data.
5. Procedures defining corrective actions for all off-control point chemistry conditions, and
6. A procedure identifying: (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

6.18 Deleted

*The Solid Radioactive Waste Treatment System shall be operated in accordance with the Process Control Program to process wet radioactive wastes to meet shipping and burial ground requirements.

JAN 08 2002

6.19 CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the primary containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exception to NEI 94-01, Rev. 0, "Industry Performance-Based Option of 10 CFR Part 50, Appendix J": The first Type A test performed after the June 10, 1995 Type A test shall be performed no later than June 10, 2010.

The peak calculated primary Containment internal pressure for the design basis loss of coolant accident is P_a.

The maximum allowable primary containment leakage rate, L_a, at P_a, is 0.5% of primary containment air weight per day.

Leakage rate acceptance criteria are:

a. Primary containment overall leakage rate acceptance criterion is $< 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the combined Type B and Type C tests, and $< 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. For each door, pressure decay is ≤ 0.1 psig when pressurized to ≥ 25 psig for at least 15 minutes.

The provisions of SR 4.0.2 do not apply for test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of SR 4.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

6.20 RADIOACTIVE EFFLUENT CONTROLS PROGRAM

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the REMODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the REMODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to ten times the concentration values in Appendix B, Table 2, Column 2 to 10CFR 20.1001-20.2402;

6.20 RADIOACTIVE EFFLUENT CONTROLS PROGRAM (CONT.)

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the REMODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the REMODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the REMODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

   1. For noble gases: a dose rate $\leq$ 500 mrem/yr to the whole body and a dose rate $\leq$ 3000 mrem/yr to the skin, and

   2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: a dose rate $\leq$ 1500 mrem/yr to any organ;

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of Specification 4.0.2 and Specification 4.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

6.21 RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provided (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the REMODCM, (2) conform to that guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

a. Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the REMODCM.

b. A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

c. Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

6.22 REACTOR COOLANT PUMP FLYWHEEL INSPECTION PROGRAM

This program shall provide for the inspection of each reactor coolant pump flywheel by either qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius, or a surface examination (magnetic particle testing and/or penetrant testing) of exposed surfaces defined by the volume of the disassembled flywheels at least once every 10 years.

6.23 TECHNICAL SPECIFICATIONS (TS) BASES CONTROL PROGRAM

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license or

   2. A change in the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 6.23.b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

6.24 Diesel Fuel Oil Test Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

    1. An API gravity or an absolute specific gravity within limits,

    2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

    3. Water and sediment ≤ 0.05%.

b. Within 31 days following addition of the new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil, and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 92 days in accordance with ASTM D-2276-78, Method A.

The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the Diesel Fuel Oil Test Program test frequencies.

6.25 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Regulatory Guide 1.35, Revision 3, 1989.

The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

Any abnormal degradation of the containment structure detected during the tests required by the Pre-stressed Concrete Containment Tendon Surveillance Program shall be reported to the NRC within 30 days. The report shall include a description of the tendon condition, the condition of the concrete (especially at tendon anchorages), the inspection procedures, the tolerances on cracking, and the corrective action taken. This Tendon Surveillance Report is an administrative requirement listed in Technical Specifications 6.9.2, "Special Reports."