UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

ENTERGY ARKANSAS, INC.

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-368

ARKANSAS NUCLEAR ONE, UNIT 2

FACILITY OPERATING LICENSE

License No. NPF-6

1. The Nuclear Regulatory Commission (the Commission) having found that:

   A. The issuance of this license to Entergy Arkansas, Inc. complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. Construction of Arkansas Nuclear One, Unit 2 (the facility) has been substantially completed in conformity with Construction Permit No. CPPR-89 and the application, as amended, the provisions of the Act and the regulations of the Commission;

   C. The facility requires exemptions from certain requirements of (1) Sections 50.55a(g)(2) and 50.55a(g)(4) of 10 CFR Part 50, (2) Appendices G and H to 10 CFR Part 50 and (3) Appendix J to 10 CFR Part 50 for a period of three years. These exemptions are described in the Office of Nuclear Reactor Regulation's safety evaluations supporting the granting of these exemptions which are enclosed in the letter transmitting this license amendment. These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. The exemptions are, therefore, hereby granted. With the granting of these exemptions, the facility will operate in conformity with the application, as amended, the provisions of the Act, and the regulations of the Commission;

   D. There is reasonable assurance: (i) that the activities authorized by this operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission;

   E. Entergy Operations, Inc. (EOI)* is technically and financially qualified to engage is the activities authorized by this operating license in accordance with the regulations of the Commission;

F. Entergy Arkansas, Inc. has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

G. The issuance of this amended operating license will not be inimical to the common defense and security or to the health and safety of the public;

H. After weighing the environmental, economic, technical and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Facility Operating License No. NPF-6 subject to the conditions for protection of the environment set forth herein, is in accordance with 10 CFR Part 51 (formerly Appendix D to 10 CFR Part 50) of the Commission's regulations and all applicable requirements have been satisfied; and

I. The receipt, possession, and use of source, byproduct and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70, including 10 CFR Sections 30.33, 40.32, 70.23 and 70.31.

2. Facility Operating License No. NPF-6 is hereby issued to Entergy Arkansas, Inc. and Entergy Operations, Inc. to read as follows:

A. This amended license applies to Arkansas Nuclear One, Unit 2, a pressurized water reactor and associated equipment (the facility) owned by Entergy Arkansas, Inc. The facility is located in Pope County, Arkansas and is described in the Final Safety Analysis Report as supplemented and amended (Amendments 20 through 47) and the Environmental Report as supplemented and amended (Amendments 1 through 7).

B. Subject to the Conditions and requirements incorporated herein, the Commission hereby licenses;

(1) Entergy Arkansas, Inc. pursuant to Section 103 of the Act and 10 CFR Part 50, to possess but not operate the facility at the designated location in Pope County, Arkansas in accordance with the procedures and limitations set forth in this license.

(2) EOI, pursuant to Section 103 of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use, and operate the facility at the designated location in Pope County, Arkansas in accordance with the procedures and limitations set forth in this amended license;

(3) EOI, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time at the facility site and as designated solely for the facility, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

Implementation Dates for Proposed Modifications (Continued)

Applicable Section of NUREG-0223		Date
3.9	Protection of Redundant Cables in the Lower South Electrical Penetration Room (2111-T)	September 30, 1978
3.10	Protection of Safe Shutdown Cables in the Upper South Piping Penetration Room (2084-DD)	September 30, 1978
3.11	Protection of Redundant Reactor Protection System Cables (2136-I)	*, **
3.12	Fire Dampers	September 30, 1978
3.13	Portable Extinguisher for the Control Room (2199-J)	November 15, 1978
3.14	Smoke Detectors	*, **
3.15	Manual Hose Stations (2055-JJ, 2084-DD, Containment, Elev. 317' of Auxiliary Building)	*, **
3.16	Portable Smoke Exhaust Equipment	December 1, 1978
3.17	Emergency Lighting	December 1, 1978
3.18	Reactor Coolant Pump Oil Collection System	*
3.19	Control of Fire Doors	March 31, 1979
3.20	Administrative Control Changes	December 1, 1978

(Numbers in parentheses refer to fire zone designations in the AP&L fire hazards analysis.)

* Prior to startup following the first regularly scheduled refueling outage.

** Technical Specifications covering these items should be proposed not later than 90 days prior to implementation.

2.C.(3)(f) Deleted per Amendment 24, 6/19/81.

2.C.(3)(g) Deleted per Amendment 93, 4/25/89.

2.C.(3)(h) Deleted per Amendment 29, (3/4/82) and its correction letter, (3/15/82).

(i) Containment Radiation Monitor

AP&L shall, prior to July 31, 1980 submit for Commission review and approval documentation which establishes the adequacy of the qualifications of the containment radiation monitors located inside the containment and shall complete the installation and testing of these instruments to demonstrate that they meet the operability requirements of Technical Specification No. 3.3.3.6. Am. 102, 12-14-89

2.C.(3)(j) Deleted per Amendment 7, 12/1/78.

2.C.(3)(k) Deleted per Amendment 12, 6/12/79 and Amendment 31, 5/12/82.

2.C.(3)(l) Deleted per Amendment 24, 6/19/81.

2.C.(3)(m) Deleted per Amendment 12, 6/12/79.

2.C.(3)(n) Deleted per Amendment 7, 12/1/78.

2.C.(3)(o) Deleted per Amendment 7, 12/1/78.

2.C.(3)(p) Deleted per Amendment 255, 9/28/04.

2.C.(4) (Number has never been used.)

2.C.(5) Deleted per Amendment 255, 9/28/04.

2.C.(6) Deleted per Amendment 255, 9/28/04.

2.C.(7) Deleted per Amendment 78, 7/22/86.

(8) Antitrust Conditions

EOI shall not market or broker power or energy from Arkansas Nuclear One, Unit 2. Entergy Arkansas, Inc. is responsible and accountable for the actions of its agents to the extent said agent's actions affect the marketing or brokering of power or energy from ANO, Unit 2.

(9) Rod Average Fuel Burnup

Entergy Operations is authorized to operate the facility with an individual rod average fuel burnup (burnup averaged over the length of a fuel rod) not to exceed 60 megawatt-days/kilogram or uranium.

D. Physical Protection

EOI shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans, including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plan, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Arkansas Nuclear One Industrial Security Plan," with revisions submitted through August 4, 1995. The Industrial Security Plan also includes the requirements for guard training and qualification in Appendix A of the safeguards contingency events in Chapter 7. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

INDEX

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

BASES

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

BASES

BASES

INDEX

ADMINISTRATIVE CONTROLS

ADMINISTRATIVE CONTROLS

CHANNEL FUNCTIONAL TEST

1.11 A CHANNEL FUNCTIONAL TEST shall be:

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

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

c. Digital computer channels – The exercising of the digital computer hardware using diagnostic programs and the injection of simulated process data into the channel to verify OPERABILITY.

CORE ALTERATION

1.12 CORE ALTERATION shall be the movement or manipulation 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 ALTERATION shall not preclude completion of movement of a component to a safe conservative 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 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 (except controlled 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, or

c. Reactor coolant system leakage through a steam generator to the secondary system.

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.

AZIMUTHAL POWER TILT – T_q

1.17 AZIMUTHAL POWER TILT shall be the power asymmetry between azimuthally symmetric fuel assemblies.

DOSE EQUIVALENT I-131

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

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

1.19 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MEV) for isotopes, other than iodines, with half lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

STAGGERED TEST BASIS

1.20 A STAGGERED TEST BASIS shall consist of:

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

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

FREQUENCY NOTATION

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

MEMBER(S) OF THE PUBLIC

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

PURGE – PURGING

1.30 PURGE or PURGING is the controlled process of discharging air or gas from a confinement to reduce airborne radioactive concentrations in such a manner that replacement air or gas is required to purify the confinement.

EXCLUSION AREA

1.31 The EXCLUSION AREA is that area surrounding ANO within a minimum radius of .65 miles of the reactor buildings and controlled to the extent necessary by the licensee for purposes of protection of individuals from exposure to radiation and radioactive materials.

UNRESTRICTED AREA

1.32 An UNRESTRICTED AREA shall be any area at or beyond the exclusion area boundary.

CORE OPERATING LIMITS REPORT

1.33 The CORE OPERATING LIMITS REPORT is the ANO-2 specific document that provides 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 Technical Specification 6.6.5. Plant operation within these operating limits is addressed in individual specifications.

REACTIVITY CONTROL SYSTEMS

BORON DILUTION

LIMITING CONDITION FOR OPERATION

3.1.1.3 The flow rate of reactor coolant through the reactor coolant system shall be ≥ 2000 gpm whenever a reduction in Reactor Coolant System boron concentration is being made.

APPLICABILITY: ALL MODES.

ACTION:

With the flow rate of reactor coolant through the reactor coolant system < 2000 gpm, immediately suspend all operations involving a reduction in boron concentration of the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

4.1.1.3 The flow rate of reactor coolant through the reactor coolant system shall be determined to be ≥ 2000 gpm within one hour 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 or containment spray pump is in operation as a shutdown cooling pump and supplying ≥ 2000 gpm through the reactor coolant system.

POWER DISTRIBUTION LIMITS

RADIAL PEAKING FACTORS

LIMITING CONDITION FOR OPERATION

3.2.2 The measured PLANAR RADIAL PEAKING FACTORS (F^m_{xy}) shall be less than or equal to the PLANAR RADIAL PEAKING FACTORS (F^c_{xy}) used in the Core Operating Limit Supervisory System (COLSS) and in the Core Protection Calculators (CPC).

APPLICABILITY: MODE 1 above 20% of RATED THERMAL POWER*

ACTION:

With a F^m_{xy} exceeding a corresponding F^c_{xy}, within 6 hours either:

a. Adjust the CPC addressable constants to increase the multiplier applied to PLANAR RADIAL PEAKING FACTOR by a factor equivalent to $\geq F^m_{xy} / F^c_{xy}$ and restrict subsequent operation so that a margin to the COLSS operating limits of at least $[(F^m_{xy}/F^c_{xy}) - 1.0] \times 100\%$ is maintained; or

b. Adjust the affected PLANAR RADIAL PEAKING FACTORS (F^c_{xy}) used in the COLSS and CPC to a value greater than or equal to the measured PLANAR RADIAL PEAKING FACTORS (F^m_{xy}); or

c. Be in at least HOT STANDBY.

SURVEILLANCE REQUIREMENTS

4.2.2.1 The provisions of Specification 4.0.4 are not applicable.

4.2.2.2 The measured PLANAR RADIAL PEAKING FACTORS (F^m_{xy}), obtained by using the incore detection system, shall be determined to be less than or equal to the PLANAR RADIAL PEAKING FACTORS (F^c_{xy}) used in the COLSS and CPC at the following intervals:

a. After each fuel loading with THERMAL POWER greater than 40% but prior to operation above 70% of RATED THERMAL POWER, and

b. At least once per 31 days of accumulated operation in MODE 1.

* See Special Test Exception 3.10.2.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS

ACTION 2 – With the number of channels OPERABLE one less than the Total Number of Channels, operation in the applicable MODES may continue provided the inoperable channel is placed in the bypassed or tripped condition within 1 hour. If the inoperable channel is bypassed for greater than 48 hours, the desirability of maintaining this channel in the bypassed condition shall be reviewed as soon as possible but no later than the next regularly scheduled OSRC meeting in accordance with the Quality Assurance Program Manual (QAPM). The channel shall be returned to OPERABLE status prior to startup following the next COLD SHUTDOWN.

With a channel process measurement circuit that affects multiple functional units inoperable or in test, bypass or trip all associated functional units as listed below.

Process Measurement Circuit	Functional Unit Bypassed
1. Linear Power (Subchannel or Linear)	Linear Power Level – High Local Power Density – High DNBR – Low Log Power Level – High*
2. Pressurizer Pressure – NR	Pressurizer Pressure – High Local Power Density – High DNBR – Low
3. Containment Pressure – NR	Containment Pressure – High (RPS) Containment Pressure – High (ESFAS) Containment Pressure – High-High (ESFAS)
4. Steam Generator 1 Pressure	Steam Generator 1 Pressure – Low Steam Generator 1 ΔP (EFAS 1) Steam Generator 2 ΔP (EFAS 2)
5. Steam Generator 2 Pressure	Steam Generator 2 Pressure – Low Steam Generator 1 ΔP (EFAS 1) Steam Generator 2 ΔP (EFAS 2)
6. Steam Generator 1 Level	Steam Generator 1 Level – Low Steam Generator 1 ΔP (EFAS 1)
7. Steam Generator 2 Level	Steam Generator 2 Level – Low Steam Generator 2 ΔP (EFAS 2)
8. Core Protection Calculator	Local Power Density – High DNBR – Low

* Only for failure common to both linear power and log power.

TABLE 3.3-3 (Continued)

TABLE NOTATION

(a) Trip function may be bypassed in this MODE when pressurizer pressure is below 400 psia; bypass shall be automatically removed before pressurizer pressure exceeds 500 psia.

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

(c) Remote manual not provided for RAS. These are local manuals at each ESF auxiliary relay cabinet.

ACTION STATEMENTS

ACTION 9 – 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 COLD SHUTDOWN within the following 30 hours.

ACTION 10 – With the number of channels OPERABLE one less than the Total Number of Channels, operation in the applicable MODES may continue provided the inoperable channel is placed in the bypassed or tripped condition within 1 hour. If the inoperable channel is bypassed for greater than 48 hours, the desirability of maintaining this channel in the bypassed condition shall be reviewed as soon as possible but no later than the next regularly scheduled OSRC meeting in accordance with the Quality Assurance Program Manual (QAPM). The channel shall be returned to OPERABLE status prior to startup following the next COLD SHUTDOWN.

If an inoperable Steam Generator ΔP or RWT Level – Low channel is placed in the tripped condition, remove the inoperable channel from the tripped condition within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

With a channel process measurement circuit that affects multiple functional units inoperable or in test, bypass or trip all associated functional units as listed below.

Process Measurement Circuit	Functional Unit Bypassed
1. Containment Pressure – NR	Containment Pressure – High (RPS) Containment Pressure – High (ESFAS) Containment Pressure – High-High (ESFAS)
2. Steam Generator 1 Pressure	Steam Generator 1 Pressure – Low Steam Generator 1 ΔP (ESFAS 1) Steam Generator 2 ΔP (ESFAS 2)
3. Steam Generator 2 Pressure	Steam Generator 2 Pressure – Low Steam Generator 1 ΔP (ESFAS 1) Steam Generator 2 ΔP (ESFAS 2)
4. Steam Generator 1 Level	Steam Generator 1 Level – Low Steam Generator 1 ΔP (EFAS 1)
5. Steam Generator 2 Level	Steam Generator 2 Level – Low Steam Generator 2 ΔP (EFAS 2)

TABLE 3.3-4

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	≤ 18.3 psia	≤ 18.490 psia
c. Pressurizer Pressure – Low	≥ 1650 psia (1)	≥ 1618.9 psia
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure – High-High	≤ 23.3 psia	≤ 23.490 psia
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure – High	≤ 18.3 psia	≤ 18.490 psia

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
4. MAIN STEAM AND FEEDWATER ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure – Low	≥ 751 psia (2)	≥ 738.6 psia (2)
5. CONTAINMENT COOLING (CCAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure – High	≤ 18.3 psia	≤ 18.490 psia
c. Pressurizer Pressure – Low	≥ 1650 psia	≥ 1618.9 psia
6. RECIRCULATION (RAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Tank – Low	6.0 ± 0.5% indicated level	between 5.111% and 6.889% indicated level
7. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage	(4)	2300 ± 699 volts with a 0.64 ± 0.34 second time delay
b. 460 volt Emergency Bus Undervoltage	(4)	429.6 ± 6.4 volts with an 8.0 ± 1.0 second time delay

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level – Low	≥ 22.2% (3)	≥ 21.5% (3)
c. Steam Generator ΔP– High (SG-A > SG-B)	≤ 90 psi	≤ 99.344 psi
d. Steam Generator ΔP– High (SG-B > SG-A)	≤ 90 psi	≤ 99.344 psi
e. Steam Generator (A&B) Pressure – Low	≥ 751 psia (2)	≥ 738.6 psia (2)

(1) Value may be decreased manually, to a minimum of ≥ 100 psia, during a planned reduction in pressurizer pressure, provided the margin between the pressurizer pressure and this value is maintained at ≤ 200 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip set-point is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed before pressurizer pressure exceeds 500 psia.

(2) Value may be decreased manually during a planned reduction in steam generator pressure, provided the margin between the steam generator pressure and this value is maintained at ≤ 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

(3) % of the distance between steam generator upper and lower narrow range level instrument nozzles.

(4) The trip value for this function is listed in the surveillance test procedures. The trip value will ensure that adequate protection is provided when all the applicable calibration tolerances, channel uncertainties, and time delays are taken into account.

(Next Page is 3/4 3-21)

INSTRUMENTATION

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

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 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION shown in Table 3.3-6.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 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.

TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. AREA MONITORS					
a. Spent Fuel Pool Area Monitor	1	Note 1	$\leq 1.5 \times 10^{-2}$ R/hr	10^{-4} - 10^{1} R/hr	13
b. Containment High Range	2	1, 2, 3, & 4	Not Applicable	1 - 10^{7} R/hr	18
2. PROCESS MONITORS					
a. Containment Purge and Exhaust Isolation	1	5 & 6	$\leq$ 2 x background	10 - 10^{6} cpm	16
b. Control Room Ventilation Intake Duct Monitors	2	Note 2	$\leq$ 2 x background	10 - 10^{6} cpm	17, 20, 21
c. Main Steam Line Radiation Monitors	1/Steam Line	1, 2, 3, & 4	Not Applicable	10^{-1} - 10^{4} mR/hr	19

Note 1 - With fuel in the spent fuel pool or building.
Note 2 - MODES 1, 2, 3, 4, and during handling of irradiated fuel.

TABLE 3.3-6 (Continued)

TABLE NOTATION

ACTION 13 – With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 16 – With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, complete the following:

a. If performing CORE ALTERATIONS or moving irradiated fuel within the reactor building, secure the containment purge system or suspend CORE ALTERATIONS and movement of irradiated fuel within the reactor building.

b. If a containment PURGE is in progress, secure the containment purge system.

c. If continuously ventilating, verify the SPING monitor operable or perform the ACTIONS of the Offsite Dose Calculation Manual, Appendix 2,Table 2.2-1, or secure the containment purge system.

ACTION 17 – In MODE 1, 2, 3, or 4, with no channels OPERABLE, within 1 hour initiate and maintain operation of the control room emergency ventilation system (CREVS) in the recirculation mode of operation or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN in the following 30 hours.

ACTION 18 – With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, (1) either restore the inoperable channel to OPERABLE status within 7 days or (2) prepare and submit a Special Report to the NRC 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. With both channels inoperable, initiate alternate methods of monitoring the containment radiation level within 72 hours in addition to the actions described above.

ACTION 19 – 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 event, or

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

ACTION 20 – In MODE 1, 2, 3, or 4 with the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, within 7 days restore the inoperable channel to OPERABLE status or initiate and maintain the CREVS in the recirculation mode of operation. Otherwise, be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN in the following 30 hours.

ACTION 21 - During handling of irradiated fuel with one or two channels inoperable, immediately place one OPERABLE CREVS train in the emergency recirculation mode or immediately suspend handling of irradiated fuel.

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. Spent Fuel Pool Area Monitor	S	R	M	Note 1
b. Containment High Range	S	R Note 4	M	1, 2, 3, & 4
2. PROCESS MONITORS				
a. Containment Purge and Exhaust Isolation	Note 2	R	Note 3	5 & 6
b. Control Room Ventilation Intake Duct Monitors	S	R	M Note 6	Note 5
c. Main Steam Line Radiation Monitors	S	R	M	1, 2, 3, & 4

Note 1 – With fuel in the spent fuel pool or building.
Note 2 – Within 8 hours prior to initiating containment purge operations and at least once per 12 hours during containment purge operations.
Note 3 – Within 31 days prior to initiating containment purge operations and at least once per 31 days during containment purge operations.
Note 4 – Acceptable criteria for calibration are provided in Table II.F.1-3 of NUREG-0737.
Note 5 – MODES 1, 2, 3, 4, and during handling of irradiated fuel.
Note 6 - When the Control Room Ventilation Intake Duct Monitor is placed in an inoperable status solely for performance of this Surveillance, entry into associated ACTIONS may be delayed up to 3 hours.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Logarithmic Neutron Channel	2C80	10^{-8} – 200%	1
2. Startup Channel	2C80	1 – 10^{6} cps	1
3. Reactor Trip Breaker Indication	-	OPEN-CLOSE	1/trip breaker
4. Reactor Coolant Cold Leg Temperature	2C80	0 - 600°F	1
5. Pressurizer Pressure	2C80	0 – 3000 psia	1
6. Pressurizer Level	2C80	0 – 100%	1
7. Steam Generator Pressure	2C80	0 – 1200 psia	1/steam generator
8. Steam Generator Level	2C80 and Local (at EFW Valves Control)	0 – 100%	1/steam generator
9. Shutdown Cooling Flow Rate	2C80	0 – 8000 gpm	1
10. Condensate Storage Tank Level	2C80	0 – 100%	1

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT		CHANNEL CHECK	CHANNEL CALIBRATION
1.	Logarithmic Neutron Channel	M	N.A.
2.	Startup Channel	M	N.A.
3.	Reactor Trip Breaker Indication	M	N.A.
4.	Reactor Coolant Cold Leg Temperature	M	R
5.	Pressurizer Pressure	M	R
6.	Pressurizer Level	M	R
7.	Steam Generator Level	M	R
8.	Steam Generator Pressure	M	R
9.	Shutdown Cooling Flow Rate	M	R
10.	Condensate Storage Tank Level	M	R

TABLE 3.3-10

POST-ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT		MINIMUM CHANNELS OPERABLE	ACTION
1.	Containment Pressure (Normal Design Range)	2	1
2.	Containment Pressure (High Range)	2	2
3.	Pressurizer Pressure	2	1
4.	Pressurizer Water Level	2	1
5.	Steam Generator Pressure	2/steam generator	1
6.	Steam Generator Water Level	2/steam generator	1
7.	Refueling Water Tank Water Level	2	1
8.	Containment Water Level – Wide Range	2	2
9.	Emergency Feedwater Flow Rate	1/steam generator	1
10.	Reactor Coolant System Subcooling Margin Monitor	1	1
11.	Pressurizer Safety Valve Acoustic Position Indication	1/Valve	1
12.	Pressurizer Safety Valve Tail Pipe Temperature	1/Valve	1
13.	In Core Thermocouples (Core Exit Thermocouples)	2/core quadrant	1
14.	Reactor Vessel Level Monitoring System (RVLMS)	2	3, 4

TABLE 3.3-10 (cont'd)

POST-ACCIDENT MONITORING INSTRUMENTATION

Action 1: With the number of OPERABLE post-accident monitoring channels less than required by Table 3.3-10, either restore the inoperable channel to OPERABLE status within 30 days, or be in HOT SHUTDOWN within the next 12 hours.

Action 2: With the number of OPERABLE post-accident monitoring channels less than required by Table 3.3-10, either restore the inoperable channel to OPERABLE status within 30 days, or be in HOT SHUTDOWN within the next 12 hours.

If only one channel is inoperable and containment entry is required to restore the inoperable channel, the channel need not be restored until the following refueling outage.

Action 3: With the number of OPERABLE channels one less than the minimum number of channels required to be OPERABLE:

a. If repairs are feasible, restore the inoperable channel to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. If repair is not feasible without shutting down, operations may continue and a special report shall be submitted to the NRC within 30 days following the failure; describing the action taken, the cause of the inoperability, and the plans and schedule for restoring the channel to OPERABLE status during the next scheduled refueling outage.

Action 4: With the number of OPERABLE channels two less than the minimum channels required to be OPERABLE:

a. If repairs are feasible, restore at least one inoperable channel to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. If repair is not feasible without shutting down, operation may continue and a special report shall be submitted to the NRC within 30 days following the failure; describing the action taken, the cause of the inoperability, and the plans and schedule for restoring the channels to OPERABLE status during the next scheduled refueling outage.

REACTOR COOLANT SYSTEM

STEAM GENERATORS

LIMITING CONDITION FOR OPERATION

3.4.5 Each steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.5 Each steam generator shall be demonstrated OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

EMERGENCY CORE COOLING SYSTEMS

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

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each sub-system comprised of:

a. One OPERABLE high-pressure safety injection (HPSI) train,

b. One OPERABLE low-pressure safety injection (LPSI) train, and

c. An independent OPERABLE flow path capable of taking suction from the refueling water tank on a Safety Injection Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal.

APPLICABILITY: MODES 1, 2 and 3 with pressurizer pressure ≥ 1700 psia.

ACTION:

a. With one ECCS subsystem inoperable due to an inoperable LPSI train, restore the inoperable train to OPERABLE status within 7 days or be in HOT STANDBY within the next 6 hours and reduce pressurizer pressure to < 1700 psia within the following 6 hours.

b. With one or more ECCS subsystems inoperable due to conditions other than "a" above and 100% of ECCS flow equivalent to a single OPERABLE HPSI and LPSI train is available, restore the inoperable train(s) to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to < 1700 psia within the following 6 hours.

c. With less than 100% ECCS flow equivalent to either the HPSI or LPSI trains within both ECCS subsystems, restore at least one HPSI train and one LPSI train to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and reduce pressurizer pressure to < 1700 psia within the following 6 hours.

d. 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 NRC within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

EMERGENCY CORE COOLING SYSTEMS

ECCS SUBSYSTEMS – T_{avg} < 300°F

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE high-pressure safety injection pump, and

b. An OPERABLE flow path capable of taking suction from the refueling water tank on a Safety Injection Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal.

APPLICABILITY: MODES 3* and 4.

ACTION:

a. With no ECCS subsystem OPERABLE, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 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 NRC within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

SURVEILLANCE REQUIREMENTS

4.5.3 The ECCS subsystem shall be demonstrated OPERABLE per the applicable Surveillance Requirements of 4.5.2.

* With pressurizer pressure < 1700 psia.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months, during shutdown, by:

   1. Verifying that each automatic valve in the flow path actuates to its correct position on CSAS and RAS test signals.

   2. Verifying that upon a RAS test signal, the containment sump isolation valves open and that a recirculation mode flow path via an OPERABLE shutdown cooling heat exchanger is established.

   3. Verifying that each spray pump starts automatically on a CSAS test signal.

d. At least once per 5 years by performing an air or smoke flow test through each spray header and verifying each spray nozzle is unobstructed.

CONTAINMENT SYSTEMS

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3.1 Each containment isolation valve shall be OPERABLE.*

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more isolation valve(s) inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and either:

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

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate the affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or

d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1.1 Each containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by performance of a cycling test and verification of isolation time.

* Locked or sealed closed valves may be opened on an intermittent basis under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

4.6.3.1.2 Each containment isolation valve shall be demonstrated OPERABLE at least once per 18 months by verifying that on a containment isolation test signal, each isolation valve actuates to its isolation position.

4.6.3.1.3 The isolation time of each power operated or automatic containment isolation valve shall be determined to be within its limit when tested pursuant to the Inservice Testing Program.

4.6.3.1.4 The containment purge supply and exhaust isolation valves shall be demonstrated OPERABLE as specified in the Containment Leakage Rate Testing Program.

3/4.7.6 CONTROL ROOM EMERGENCY VENTILATION AND AIR CONDITIONING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 Two independent control room emergency ventilation and air conditioning systems shall be OPERABLE. (Note 1)

APPLICABILITY: MODES 1, 2, 3, 4, or during handling of irradiated fuel.

ACTION:

MODES 1, 2, 3, and 4

a. With one control room emergency air conditioning system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one control room emergency ventilation system inoperable, restore the inoperable system 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.

c. With one control room emergency air conditioning system and one control room emergency ventilation system inoperable, restore the inoperable control room emergency ventilation system to OPERABLE status within 7 days and restore the inoperable control room emergency air conditioning system to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With two control room emergency ventilation systems inoperable due to an inoperable control room boundary, restore the control room boundary to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

e. With two control room emergency ventilation systems inoperable for reasons other than ACTION d or with two control room emergency air conditioning systems inoperable, enter Specification 3.0.3.

During Handling of Irradiated Fuel

f. With one control room emergency air conditioning system inoperable, restore the inoperable system to OPERABLE status within 30 days or immediately place the OPERABLE system in operation; otherwise, suspend all activities involving the handling of irradiated fuel. The provisions of Specification 3.0.4 are not applicable.

g. With one control room emergency ventilation system inoperable, restore the inoperable system to OPERABLE status within 7 days or immediately place the control room in the emergency recirc mode of operation; otherwise, suspend all activities involving the handling of irradiated fuel. The provisions of Specification 3.0.4 are not applicable.

Note 1: The control room boundary may be open intermittently under administrative controls.

h. With one control room emergency air conditioning system and one control room emergency ventilation system inoperable:

1. restore the inoperable control room emergency ventilation system to OPERABLE status within 7 days or immediately place the control room in the emergency recirc mode of operation, and

2. restore the inoperable control room emergency air conditioning system to OPERABLE status within 30 days or immediately place the OPERABLE system in operation;

3. otherwise, suspend all activities involving the handling of irradiated fuel.

4. The provisions of Specification 3.0.4 are not applicable.

i. With both control room emergency air conditioning systems or both control room emergency ventilation systems inoperable, immediately suspend all activities involving the handling of irradiated fuel.

SURVEILLANCE REQUIREMENTS

4.7.6.1.1 Each control room emergency air conditioning system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Starting each unit from the control room, and

2. Verifying that each unit operates for at least 1 hour and maintains the control room air temperature ≤ 84°F D.B.

b. At least once per 18 months by verifying a system flow rate of 9900 cfm ± 10%.

4.7.6.1.2 Each control room emergency air filtration system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that the system operates for at least 15 minutes.

b. At least once per 18 months by verifying that on a control room high radiation signal, either actual or simulated, the system automatically isolates the control room and switches into a recirculation mode of operation.

c. By performing the required Control Room Emergency Ventilation filter testing in accordance with the Ventilation Filter Testing Program (VFTP).

d. At least once per 18 months verify VSF-9 makeup flow rate is ≥ 300 and ≤ 366 cfm when supplying the control room with outside air.

e. At least once per 18 months verify 2VSF-9 makeup flow rate is ≥ 418.5 and ≤ 511.5 cfm when supplying the control room with outside air.

SURVEILLANCE REQUIREMENTS (Continued)

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that (1) there are no visible indications of damage or impaired OPERABILITY, and (2) attachments to the foundation or supporting structure are functional and (3) fastners 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 inoperable and may be reclassified OPERABLE for the purpose of establishing the next visual inspection interval, providing that (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specifications 4.7.8.d or 4.7.8.e, as applicable. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be determined inoperable and cannot be determined OPERABLE via functional testing for the purpose of establishing the next visual inspection interval. All snubbers connected to a common hydraulic fluid reservoir shall be evaluated for operability if any snubber connected to that reservoir is determined to be inoperable.

d. Functional Tests

At least once each refueling shutdown a representative sample of snubbers shall be tested using the following sample plan.

At least 10% of the snubbers required by Specification 3.7.8 shall be functionally tested either in place or in bench test. For each snubber that does not meet the functional test acceptance criteria of Specification 4.7.8.e, an additional 10% of the snubbers shall be functionally tested until no more failures are found or until all snubbers have been functionally tested.

The representative samples for the functional test sample plans shall be randomly selected from the snubbers required by Specification 3.7.8 and reviewed before beginning the testing. The review shall ensure as far as practical that they are representative of the various configurations, operating environments, range of sizes, and capacities. Snubbers placed in the same locations as snubbers which failed the previous functional test shall be retested at the

If any snubber selected for functional testing either fails to activate or fails to move, i.e., frozen-in-place, the cause will be evaluated and, if caused by manufacturer or design deficiency, all snubbers of the same type subject to the same defect shall be evaluated in a manner to ensure their OPERABILITY. This requirement shall be independent of the requirements stated in Specification 4.7.8.d for snubbers not meeting the functional test acceptance criteria.

g. Preservice Testing of Repaired, Replacement and New Snubbers

Preservice operability testing shall be performed on repaired, replacement or new snubbers prior to installation. Testing may be at the manufacturer's facility. The testing shall verify the functional test acceptance criteria in 4.7.8.e.

In addition, a preservice inspection shall be performed on each repaired, replacement or new snubber and shall verify that:

1) There are no visible signs of damage or impaired operability as a result of storage, handling or installation;

2) The snubber load rating, location, orientation, position setting and configuration (attachment, extensions, etc.), are in accordance with design;

3) Adequate swing clearance is provided to allow snubber movement;

4) If applicable, fluid is at the recommended level and fluid is not leaking from the snubber system;

5) Structural connections such as pins, bearings, studs, fasteners and other connecting hardware such as lock nuts, tabs, wire, and cotter pins are installed correctly.

h. Snubber Seal Replacement Program

The seal service life of hydraulic snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The expected service life for the various seals, seal materials, and applications shall be determined and established based on engineering information and the seals shall be replaced so that the expected service life will not be exceeded during a period when the snubber is required to be OPERABLE. The seal replacements shall be documented.

TABLE 4.7.8-1

SNUBBER VISUAL INSPECTION INTERVAL

NUMBER OF INOPERABLE SNUBBERS

Population per 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
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

Note 1: The next visual inspection interval for a snubber category shall be determined based upon the previous inspection interval and the number of inoperable 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, categories must be determined and documented before any inspection and that determination shall be the basis upon which to determine the next inspection interval for that category.

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

TABLE 4.7.8-1 (Continued)

SNUBBER VISUAL INSPECTION INTERVAL

Note 3: If the number of inoperable 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 inoperable 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 inoperable 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 inoperable 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 inoperable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Column B and C.

Note 6: Specified surveillance intervals may be adjusted plus or minus 25 percent to accommodate normal test and surveillance schedule intervals up to and including 48 months, with the exception that inspection of inaccessible snubbers may be deferred to the next shutdown when plant conditions allow five days for inspection. See Note 7 for definition of interval as applied to snubber visual inspections. The provisions of Specification 4.0.2 regarding surveillance intervals are not applicable.

Note 7: Interval as defined for the shock suppressors (snubbers) visual inspection surveillance requirements is the period of time starting when the unit went into cold shutdown for refueling, and ending when the unit goes into cold shutdown for its next scheduled refueling. This period of time is nominally considered to be an 18 month period, or a 24 month period based on the type of fuel being used. However, the period of time (interval) could be shorter or longer due to plant operating variables such as fuel life and operating performance.

3/4.7.12 SPENT FUEL POOL STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.7.12 The structural integrity of the spent fuel pool shall be maintained in accordance with Specification 4.7.12.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel pool.

ACTION:

a. With the structural integrity of the spent fuel pool not conforming to the above requirements, in lieu of any other report, prepare and submit a Special Report to the NRC within 30 days of a determination of such non-conformity.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.12.1 Inspection Frequencies - The structural integrity of the spent fuel pool shall be determined per the acceptance criteria of Specification 4.7.12.2 at the following frequencies:

a. At least once per 92 days after the pool is filled with water. If no abnormal degradation or other indications of structural distress are detected during five consecutive inspections, the inspection interval may be extended to at least once per 5 years.

b. Within 24 hours following any seismic event which actuates or should have actuated the seismic monitoring instrumentation.

4.7.12.2 Acceptance Criteria - The structural integrity of the spent fuel pool shall be determined by a visual inspection of at least the interior and exterior surfaces of the pool, the struts in the tilt pit, the surfaces of the separation walls, and the structural slabs adjoining the pool walls. This visual inspection shall verify no changes in the concrete crack patterns, no abnormal degradation or other signs of structural distress (i.e, cracks, bulges, out of plumbness, leakage, discolorations, efflorescence, etc.).

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

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:

1. A day fuel tank containing a minimum volume of 300 gallons of fuel,
2. A separate fuel storage system, and
3. A separate fuel transfer pump.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one offsite A.C. circuit of the above required A.C. electrical power sources inoperable, perform the following:

1. Demonstrate the OPERABILITY of the remaining offsite A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter, and
2. Restore the offsite A.C. circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Startup Transformer No. 2 may be removed from service for up to 30 days as part of a preplanned preventative maintenance schedule. The 30-day allowance may be applied not more than once in a 10-year period. The provisions of Specification 3.0.4 are not applicable to Startup Transformer No. 2 during the 30-day preventative maintenance period.

c. With one offsite A.C. circuit and one diesel generator of the above required A.C. electrical power sources inoperable, perform the following:

1. Demonstrate the OPERABILITY of the remaining offsite A.C. circuit by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and,

2. If the diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, then

i. Demonstrate the OPERABILITY of the remaining OPERABLE diesel generator by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours except when:

a. The remaining diesel generator is currently in operation, or

b. The remaining diesel generator has been demonstrated OPERABLE within the previous 8 hours, and

3. Restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours, and

4. Restore the remaining inoperable A.C. Source to an OPERABLE status (Offsite A.C. Circuit within 72 hours or Diesel Generator within 14 days(see b.3, Note 1)) based on the time of the initiating event that caused the inoperability or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With two offsite A.C. circuits of the above required A.C. electrical power sources inoperable, perform the following:

1. Perform Surveillance Requirement 4.8.1.1.2.a.4 on the diesel generators within the next 8 hours except when:

i. The diesel generators are currently in operation, or

ii. The diesel generators have been demonstrated OPERABLE within the previous 8 hours, and

2. Restore one of the inoperable offsite A.C. circuits to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours, and

3. Restore both A.C. circuits within 72 hours of the initiating event or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring (manually and automatically) unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE: (Note 1)

a. At least once per 31 days on a STAGGERED TEST BASIS by:

1. Verifying the fuel level in the day fuel tank.

2. deleted

3. Verifying the fuel transfer pump can be started and transfers fuel from the storage system to the day tank.

4. Verifying the diesel starts from a standby condition and accelerates to at least 900 rpm in ≤ 15 seconds. (Note 2)

5. Verifying the generator is synchronized, loaded to an indicated 2600 to 2850 Kw and operates for ≥ 60 minutes. (Notes 3 & 4)

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

b. deleted

Note 1
All planned diesel generator starts for the purposes of these surveillances may be preceded by prelube procedures.

Note 2
This diesel generator start from a standby condition in ≤ 15 sec. shall be accomplished at least once every 184 days. All other diesel generator starts for this surveillance may be in accordance with vendor recommendations.

Note 3
Diesel generator loading may be accomplished in accordance with vendor recommendations such as gradual loading.

Note 4
Momentary transients outside this load band due to changing loads will not invalidate the test. Load ranges are allowed to preclude over- loading the diesel generators.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by:

1. Deleted

2. Verifying during shutdown that the automatic sequence time delay relays are OPERABLE at their setpoint ± 10% of the elapsed time for each load block.

3. Verifying during shutdown the generator capability to reject a load of greater than or equal to its associated single largest post-accident load, and maintain voltage at 4160 ± 500 volts and frequency at 60 ± 3 Hz.

4. Verifying during shutdown the generator capability to reject a load of 2850 Kw without exceeding 75% of the difference between nominal speed and the overspeed trip setpoint, or 15% above nominal, whichever is lower.

5. Simulating during shutdown a loss of offsite power by itself, and:

   a. Verifying de-energization of the emergency busses and load shedding from the emergency busses.

   b. Verifying the diesel starts from a standby condition on the undervoltage auto-start signal, energizes the emergency busses with permanently connected loads, energizes the auto-connected shutdown loads through the time delay relays and operates for ≥ 5 minutes while its generator is loaded with the shutdown loads.

6. Verifying during shutdown that on a Safety Injection Actuation Signal (SIAS) actuation test signal (without loss of offsite power) the diesel generator starts on the auto-start signal and operates on standby for ≥ 5 minutes.

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:

1. A day fuel tank containing a minimum volume of 300 gallons of fuel,

2. A fuel storage system, and

3. A fuel transfer pump.

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.

SURVEILLANCE REQUIREMENT

4.8.1.2 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Surveillance Requirements of 4.8.1.1.1 and 4.8.1.1.2 except for Requirement 4.8.1.1.2a.5.

ELECTRICAL POWER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.8.1.3 The stored diesel fuel oil shall be within limits for each required diesel generator.

APPLICABILITY: When associated diesel generator is required to be OPERABLE.

ACTION:

With the volume of the stored diesel fuel oil less than 22,500 gallons for either fuel oil storage tank or the new or stored fuel oil properties outside the limits of the Diesel Fuel Oil Testing Program, perform the following as appropriate: (Note – Separate ACTION entry is allowed for each diesel generator.)

1. If one or more fuel storage tanks contain less than 22,500 gallons and greater than 17,446 gallons, restore the fuel oil volume to within limits within 48 hours.

2. If the stored fuel oil total particulates are not within limits for one or more diesel generators, restore fuel oil total particulates to within limits within 7 days.

3. If new fuel oil properties are not within limits for the one or more diesel generators, restore stored fuel oil properties to within limits within 30 days.

4. If ACTION 1 is not met within the allowable outage time or is outside the allowable limits, or if ACTION 2 or 3 is not met within the allowable outage time, then immediately declare the associated diesel generator inoperable.

SURVEILLANCE REQUIREMENTS

4.8.1.3.1 At least once per 31 days on a STAGGERED TEST BASIS verify the fuel oil storage tank contains ≥ 22,500 gallons of fuel.

4.8.1.3.2 Verify 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.

3/4.9 REFUELING OPERATIONS

BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 With the reactor vessel head unbolted or removed, the boron concentration of the reactor coolant and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of following reactivity conditions is met:

a. Either a K_{eff} of 0.95 or less, which includes a 1% $\Delta k/k$ conservative allowance for uncertainties, or

b. A boron concentration of $\geq$ 2500 ppm, which includes a 50 ppm conservative allowance for uncertainties.

APPLICABILITY: MODE 6*.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at $\geq$ 40 gpm of $\geq$ 2500 ppm boric acid solution until K_{eff} is reduced to $\leq$ 0.95 or the boron concentration is restored to $\geq$ 2500 ppm, whichever is the more restrictive. The provisions of Specification 3.0.3 are not applicable.

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 the reactor coolant and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

* The reactor shall be maintained in MODE 6 when the reactor vessel head is unbolted or removed.

FUEL HANDLING AREA VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.11 The fuel handling area ventilation system shall be operating and discharging through the HEPA filters and charcoal adsorbers.

APPLICABILITY: Whenever irradiated fuel is being moved in the storage pool and during crane operation with loads over the storage pool.

ACTION:

a. With the fuel handling area ventilation system not operating, suspend all operations involving movement of fuel within the spent fuel pool or crane operation with loads over the spent fuel pool until the fuel handling area ventilation system is restored to operation.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.11.1 The fuel handling area ventilation system shall be determined to be in operation and discharging through the HEPA filters and charcoal adsorbers at least once per 12 hours.

4.9.11.2 The fuel handling area ventilation system shall be demonstrated OPERABLE when irradiated fuel is in the storage pool by performing the required fuel handling filter testing in accordance with the Ventilation Filter Testing Program (VFTP).

SPECIAL TEST EXCEPTIONS

GROUP HEIGHT, INSERTION AND POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The group height, insertion and power distribution limits of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.2, 3.2.3, 3.2.7 and the Minimum Channels OPERABLE requirement of Functional Unit 14 of Table 3.3-1 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 linear heat rate limit shall be maintained by either:

1. Maintaining COLSS calculated core power less than or equal to COLSS calculated core power operating limit based on linear heat rate (when COLSS is in service); or

2. Operating within the region of acceptable operation as specified in the CORE OPERATING LIMITS REPORT using any operable CPC channel (when COLSS is out of service.)

APPLICABILITY: During startup and PHYSICS TESTS.

ACTION:

With any of the above limits being exceeded while any of the above requirements are suspended, either:

a. Reduce THERMAL POWER sufficiently to satisfy the requirements of the above Specification, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined at least once per hour during PHYSICS TESTS in which any of the above requirements 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 its limits during PHYSICS TESTS above 5% of RATED THERMAL POWER in which any of the above requirements are suspended.

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Plant Manager Operations shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 An individual with an active Senior Reactor Operator (SRO) license shall be designated as responsible for the control room command function while the unit is in MODE 1, 2, 3, or 4. With the unit not in MODES 1, 2, 3, or 4, an individual with an active SRO or Reactor Operator license shall be designated as responsible for the control room command function.

6.2 ORGANIZATION

6.2.1 ONSITE AND OFFSITE 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 safety of the nuclear power unit.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements, including the unit specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications, shall be documented in the Safety Analysis Report (SAR);

b. The Plant Manager Operations shall be responsible for overall safe operation of the unit and shall have control over those onsite activities necessary for safe operation and maintenance of the unit;

c. A specified corporate executive shall have corporate responsibility for overall unit nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the unit to ensure nuclear safety. The specified corporate executive shall be identified in the SAR; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

6.2.2 UNIT STAFF

a. A non-licensed operator shall be on site when fuel is in the reactor and two additional non-licensed operators shall be on site when the reactor is in MODES 1, 2, 3, or 4.

b. The minimum shift crew composition for licensed operators shall meet the minimum staffing requirements of 10 CFR 50.54(m)(2)(i) for one unit, one control room.

c. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) for one unit, one control room, and 6.2.2.a and 6.2.2.g for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

d. An individual qualified in radiation protection procedures shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

e. The amount of overtime worked by unit staff members performing safety related functions shall be limited and controlled in accordance with the NRC Policy Statement on working hours (Generic Letter No. 82-12).

f. The operations manager or the assistant operations manager shall hold a SRO license.

g. In MODES 1, 2, 3, or 4, an individual shall provide advisory technical support for the operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI ANS 3.1-1978 for comparable positions, except for the designated radiation protection manager, who shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, September 1975.

6.4 PROCEDURES

6.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Section 7.1 of Generic Letter 82-33;

c. Fire Protection Program implementation;

d. All programs specified in Specification 6.5; and

e. Modification of core protection calculator (CPC) addressable constants. These procedures shall include provisions to ensure that sufficient margin is maintained in CPC type I addressable constants to avoid excessive operator interaction with the CPCs during reactor operation.

Modifications to the CPC software (including changes of algorithms and fuel cycle specific data) shall be performed in accordance with the most recent version of "CPC Protection Algorithm Software Change Procedure," CEN-39(A)-P, which has been determined to be applicable to the facility. Additions or deletions to CPC addressable constants or changes to addressable constant software limit values shall not be implemented without prior NRC approval.

6.5 PROGRAMS AND MANUALS

The following programs shall be established, implemented, and maintained.

6.5.1 Offsite Dose Calculation Manual (ODCM)

The ODCM 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

The ODCM 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.

Licensee initiated changes to the ODCM:

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) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after approval of the ANO general manager; and

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made effective. 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.

6.5 PROGRAMS AND MANUALS

6.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at least once per 18 months. The provisions of Surveillance Requirements 4.0.2 are applicable.

6.5.3 Iodine Monitoring

This program provides controls that ensure the capability to accurately determine the airborne iodine concentration under accident conditions. The program shall include the following:

a. Training of personnel;

b. Procedures for monitoring; and

c. Provisions for maintenance of sampling and analysis equipment.

6.5.4 Radioactive Effluent Controls Program

This program conforms with 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 ODCM, 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 ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS, conforming to 10 CFR 20, Appendix B, Table II, Column 2;

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 ODCM;

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;

6.5.4 Radioactive Effluent Controls Program (continued)

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 ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM 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 to areas beyond the site boundary conforming to the dose associated with 10 CFR 20, Appendix B, Table II, Column 1;

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 SR 4.0.2 and SR 4.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

6.5.5 Component Cyclic or Transient Limit Program

This program provides controls to track the SAR Section 5.2.1.5, cyclic and transient occurrences to ensure that components are maintained within the design limits.

6.5.6 not used

6.5.7 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendation of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. The volumetric examination per Regulatory Position C.4.b.1 will be performed on approximately 10-year intervals.

6.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Code terminology for inservice testing activities	Required frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Every 6 weeks	At least once per 42 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

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

c. The provisions of Specification 4.0.3 are applicable to inservice testing activities, and

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

6.5.9 <u>Steam Generator (SG) Tube Surveillance Program</u>

6.5.9.1 <u>Steam Generator Sample Selection and Inspection</u>

Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 6.5.9-1.

6.5.9.2 <u>Steam Generator Tube Sample Selection and Inspection</u>

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 6.5.9-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 6.5.9.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 6.5.9.4. 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 pre-service inspection) of each steam generator shall include:

   1. All non-plugged 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 6.5.9.4.a.9) 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 6.5.9-2) during each inservice inspection may be subjected to a partial 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 inspections include those portions of the tubes where imperfections were previously found.

The result 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.

6.5.9.3 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 pre-service 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.

   A one-time inspection interval of a maximum of once per 40 months is allowed for the inspection performed immediately following the 2R15 outage. This is an exception to 6.5.9.3.a in that the interval extension is based on all of the results of one inspection falling into the C-1 category.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 6.5.9-2 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 6.5.9.3.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 6.5.9-2 during the shutdown subsequent to any of the following conditions:

   1. Primary-to-secondary tube 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.

6.5.9.4 Acceptance Criteria

a. As used in this Specification

1. Tubing or Tube means that portion of the tube which forms the primary system to secondary system pressure boundary.

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

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

4. Degraded Tube means a tube containing imperfections ≥20% of nominal wall thickness caused by degradation.

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

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

7. Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging because it may become unserviceable prior to the next inspection. The plugging limit is equal to 40% of the nominal tube wall thickness.

8. 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 6.5.9.3.c, above.

9. Tube Inspection means an inspection of the steam generator tube from tube end (cold leg side) to tube end (hot leg side).

10. Pre-service Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed after the hydrostatic test and prior to POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit and all tubes containing through-wall cracks) required by Table 6.5.9-2.

TABLE 6.5.9-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE INSPECTED DURING INSERVICE INSPECTION

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

Table Notation:

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 6.5.9-2

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	Plug defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug 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., plug defective tubes and inspect 2S tubes in the other S.G. Special Report to NRC per Specification 6.6.7	Other S.G. is C-1	None	N/A	N/A
			Other S.G. is C-2	Perform action for C-2 result of second sample	N/A	N/A
			Other S.G. is C-3	Inspect all tubes in the other S.G. and plug defective tubes. Special Report to NRC per Spec. 6.6.7	N/A	N/A

S = 3 (2/n) % Where n is the number of steam generators inspected during an inspection.

6.5.10 Secondary Water Chemistry

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points;

d. Procedure for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data, and the sequence and timing of administrative events required to initiate corrective action.

6.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safeguards (ES) ventilation systems filters at the frequencies specified in Regulatory Guide 1.52, Revision 2. The VFTP is applicable to the Fuel Handling Area Ventilation System (FHAVS) and the Control Room Emergency Ventilation System (CREVS).

a. Demonstrate that an inplace cold DOP test of the high efficiency particulate (HEPA) filters shows:

1. ≥ 99% DOP removal for the FHAVS when tested at the system design flowrate of 39,700 cfm ± 10%; and

2. ≥ 99.95% DOP removal for the CREVS when tested in accordance with Regulatory Guide 1.52, Revision 2, at the system design flowrate 2000 cfm ± 10%.

b. Demonstrate that an inplace halogenated hydrocarbon test of the charcoal adsorbers shows:

1. ≥ 99.95% halogenated hydrocarbon removal for the FHAVS when tested at the system design flow rate of 39,700 cfm ± 10%; and

2. ≥ 99.95% halogenated hydrocarbon removal for the CREVS when tested in accordance with Regulatory Guide 1.52, Revision 2, at the system design flow rate of 2000 cfm ± 10%.

c. Demonstrate that a laboratory test of a sample of the charcoal adsorber meets the laboratory testing criteria of ASTM D3803-1989 when tested at 30°C and 95% relative humidity for a methyl iodide penetration of:

1. < 5% for the FHAVS; and

2. when obtained as described in Regulatory Guide 1.52, Revision 2, for CREVS

i. ≤ 2.5% for 2 inch charcoal adsorber beds; and

ii. ≤ 0.5% for 4 inch charcoal adsorber beds.

d. Demonstrate for the FHAVS and CREVS, that the pressure drop across the combined HEPA filters, other filters in the system, and charcoal adsorbers is < 6 inches of water when tested at the following system design flowrates ± 10%.

FHAVS	39,700 cfm
CREVS	2,000 cfm

The provision of SR 4.0.2 and SR 4.0.3 are applicable to the VFTP test frequencies.

6.5.12 Later

6.5.13 Diesel Fuel Oil Testing 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 within limits;

b. Within 31 days following addition of 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;

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days based on ASTM D-2276, Method A-2 or A-3; and

d. The provisions of SR 4.0.2 and SR 4.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

6.5.14 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 to the updated SAR 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 SAR.

d. Proposed changes that do not meet the criteria of 6.5.14b 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).

6.5.15 not used

6.5.16 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, 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.

In addition, the containment purge supply and exhaust isolation valves shall be leakage rate tested prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 58 psig.

The maximum allowable containment leakage rate, L_a, shall be 0.1% of containment air weight per day at P_a.

Leakage rate acceptance criteria are:

a. Containment leakage rate acceptance criteria is $\leq 1.0\ L_a$. During the first unit startup following each test performed in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for Type A tests.

b. Air lock acceptance criteria are:

   1. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2. Leakage rate for each door is $\leq 0.01\ L_a$ when pressurized to $\geq$ 10 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the Containment Leakage Rate Testing Program.

6.6 REPORTING REQUIREMENTS

6.6.1 Occupational Radiation Exposure Report

(Note: A single submittal may be made for ANO. The submittal should combine sections common to both units.)

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors), for whom monitoring was performed, receiving an annual deep dose equivalent >100 mrems and the associated collective deep dose equivalent (reported in person-rem) according to work and job functions, (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket ionization chamber, thermoluminescence dosimeter (TLD), electronic dosimeter, or film badge measurements. Small exposures totaling < 20 percent of the individual total dose need not be accounted for. In the aggregate, at least 80 percent of the total deep dose equivalent received from external sources should be assigned to specific major work functions. The report covering the previous calendar year shall be submitted by April 30 of each year.

6.6.2 Annual Radiological Environmental Operating Report

(Note: A single submittal may be made for ANO. The submittal should combine sections common to both units.)

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 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 Offsite Dose Calculation Manual (ODCM), and in 10 CFR 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 ODCM, 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 a supplementary report as soon as possible.

6.6.3 Radioactive Effluent Release Report
(Note: A single submittal may be made for ANO. The submittal shall combine sections common to both units. 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 ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

6.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

6.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining part of a reload cycle, and shall be documented in the COLR for the following:

3.1.1.1 Shutdown Margin – $T_{avg} > 200°F$
3.1.1.2 Shutdown Margin - $T_{avg} \leq 200°F$
3.1.1.4 Moderator Temperature Coefficient
3.1.3.1 CEA Position
3.1.3.6 Regulating and Group P CEA Insertion Limits
3.2.1 Linear Heat Rate
3.2.3 Azimuthal Power – Tq
3.2.4 DNBR Margin
3.2.7 Axial Shape Index

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) "The ROCS and DIT Computer Codes for Nuclear Design", CENPD-266-P-A, April 1983 (Methodology for Specifications 3.1.1.1 and 3.1.1.2 for Shutdown Margins, 3.1.1.4 for MTC, 3.1.3.6 for Regulating and Group P CEA Insertion Limits, and 3.2.4.b for DNBR Margin).

2) "CE Method for Control Element Assembly Ejection Analysis," CENPD-0190-A, January 1976 (Methodology for Specification 3.1.3.6 for Regulating and Group P CEA Insertion Limits and 3.2.3 for Azimuthal Power Tilt).

6.6.5 CORE OPERATING LIMITS REPORT (COLR) (Continued)

3) "Modified Statistical Combination of Uncertainties, CEN-356(V)-P-A, Revision 01-P-A, May 1988 (Methodology for Specification 3.2.4.c and 3.2.4.d for DNBR Margin and 3.2.7 for ASI).

4) "Calculative Methods for the CE Large Break LOCA Evaluation Model," CENPD-132-P, August 1974 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

5) "Calculational Methods for the CE Large Break LOCA Evaluation Model," CENPD-132-P, Supplement 1, February 1975 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

6) "Calculational Methods for the CE Large Break LOCA Evaluation Model," CENPD-132-P, Supplement 2-P, July 1975 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

7) "Calculative Methods for the CE Large Break LOCA Evaluation Model for the Analysis of CE and W Designed NSSS," CEN-132, Supplement 3-P-A, June 1985 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

8) "Calculative Methods for the CE Small Break LOCA Evaluation Model," CENPD-137-P, August 1974 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

9) "Calculative Methods for the CE Small Break LOCA Evaluation Model," CENPD-137, Supplement 1-P, January 1977 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

10) "Calculative Methods for the CE Small Break LOCA Evaluation Model," CENPD-137, Supplement 2-P-A, dated April, 1998 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

11) "CESEC-Digital Simulation of a Combustion Engineering Nuclear Steam Supply System," December 1981 (Methodology for Specifications 3.1.1.1 and 3.1.1.2 for Shutdown Margin, 3.1.1.4 for MTC, 3.1.3.1 for CEA Position, 3.1.3.6 for Regulating CEA and Group P Insertion Limits, and 3.2.4.b for DNBR Margin).

6.6.5 CORE OPERATING LIMITS REPORT (COLR) (Continued)

12) "Technical Manual for the CENTS Code," CENPD 282-P-A, February 1991 (Methodology for Specifications 3.1.1.1 and 3.1.1.2 for Shutdown Margin, 3.1.1.4 for MTC, 3.1.3.1 for CEA Position, 3.1.3.6 for Regulating and Group P Insertion Limits, and 3.2.4.b for DNBR Margin.

13) Letter: O.D. Parr (NRC) to F.M. Stern (CE), dated June 13, 1975 (NRC Staff Review of the Combustion Engineering ECCS Evaluation Model). NRC approval for 6.6.5.b.4), 6.6.5.b.5), and 6.6.5.b.8) methodologies.

14) Letter: O.D. Parr (NRC) to A.E. Scherer (CE), dated December 9, 1975 (NRC Staff Review of the Proposed Combustion Engineering ECCS Evaluation Model changes). NRC approval for 6.6.5.b.6) methodology.

15) Letter: K. Kniel (NRC) to A.E. Scherer (CE), dated September 27, 1977 (Evaluation of Topical Reports CENPD-133, Supplement 3-P and CENPD-137, Supplement 1-P). NRC approval for 6.6.5.b.9) methodology.

16) Letter: 2CNA038403, dated March 20, 1984, J.R. Miller (NRC) to J.M. Griffin (AP&L), "CESEC Code Verification." NRC approval for 6.6.5.b.11) methodology.

17) "Calculative Methods for the CE Nuclear Power Large Break LOCA Evaluation Model," CENPD-132-P, Supplement 4-P-A, Revision 1 (Methodology for Specification 3.1.1.4 for MTC, 3.2.1 for Linear Heat Rate, 3.2.3 for Azimuthal Power Tilt, and 3.2.7 for ASI).

c. The core operating limits shall be determined such that all applicable limits (e.g. fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling System (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

6.6.6 not used

6.6.7 Steam Generator Tube Surveillance 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 reported within 12 months following the completion of the inservice inspection. 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.

c. Results of steam generator tube inspections which fall into Category C-3 shall be reported to the Commission as denoted by Table 6.5.9-2. Notification of the Commission will be made prior to resumption of plant operation (i.e., prior to entering Mode 4). The written report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

6.6.8. Specific Activity

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 the results of one analysis after the radioiodine activity was reduced to less than 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.

6.7 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:

6.7.1 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 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.

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 for 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

6.7 HIGH RADIATION AREA (continued)

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.

6.7.2 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 designee.

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.

6.7 HIGH RADIATION AREA (continued)

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 or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation 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

(ii) Be under the surveillance as specified in the RWP, or equivalent, while in the area by means of closed circuit television, or 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.

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.