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

VIRGINIA ELECTRIC AND POWER COMPANY

DOCKET NO. 50-280

SURRY POWER STATION, UNIT NO. 1

SUBSEQUENT RENEWED FACILITY OPERATING LICENSE

Subsequent Renewed License No. DPR-32

The Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in Renewed License No. DPR-32 issued March 20, 2003, has now found that:

a. The application for Subsequent Renewed Facility Operating License No. DPR-32 filed by Virginia Electric and Power Company (VEPCO or the licensee) complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the rules and regulations of the Commission set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

b. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the subsequent period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1), and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by this subsequent renewed facility operating license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for Surry Power Station, Unit No. 1, and that any changes made to the plant's current licensing basis in order to comply with 10 CFR 54.29(a) are in accord with the Act and the Commission's regulations;

c. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

d. There is reasonable assurance: (i) that the activities authorized by this subsequent renewed 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 rules and regulations of the Commission;

e. VEPCO is technically and financially qualified to engage in the activities authorized by this subsequent renewed operating license in accordance with the rules and regulations of the Commission;

f. The applicable provisions of 10 CFR Part 140 have been satisfied; and

g. The issuance of this subsequent renewed license will not be inimical to the common defense and security or to the health and safety of the public.

On the basis of the foregoing findings regarding this facility, Renewed Facility Operating License No. DPR- 32, issued March 20, 2003, is superseded by Subsequent Renewed Facility Operating License No. DPR-32, which is hereby issued to the VEPCO to read as follows:

1. This subsequent renewed license applies to the Surry Power Station, Unit No. 1, a pressurized, light water moderated and cooled reactor, and associated steam generators and electric generating equipment (the facility). The facility is located on the licensee's 840-acre site on a point of land called Gravel Neck on the James River, approximately 14 miles northwest of Newport News and 25 miles northwest of Norfolk, Virginia, and is described in the Updated Final Safety Analysis Report.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses the licensee:

   A. Pursuant to Section 104b 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 Surry County, Virginia, in accordance with the procedures and limitations set forth in this subsequent renewed license;

   B. Pursuant to the Act and 10 CFR Parts 40 and 70, to receive, possess, and use at any time, source and special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Updated Final Safety Analysis Report;

   C. Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess and use at any time, any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

   D. Pursuant to the Act and 10 CFR Parts, 30, 40, and 70, to receive, possess and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

   E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3. This subsequent renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

   A. Maximum Power Level

      The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2587 megawatts (thermal).

   B. Technical Specifications

      The Technical Specifications contained in Appendix A, as revised through Amendment No. 317 are hereby incorporated in the subsequent renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

   C. Reports

      The licensee shall make certain reports in accordance with the requirements of the Technical Specifications.

   D. Records

      The licensee shall keep facility operating records in accordance with the requirements of the Technical Specifications.

   E. Deleted by Amendment 65

   F. Deleted by Amendment 71

   G. Deleted by Amendment 227

   H. Deleted by Amendment 227

I. Fire Protection

The licensee shall implement and maintain in effect the provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report and as approved in the SER dated September 19, 1979, (and Supplements dated May 29, 1980, October 9, 1980, December 18, 1980, February 13, 1981, December 4, 1981, April 27, 1982, November 18, 1982, January 17, 1984, February 25, 1988, and July 23, 1992), and the Safety Evaluation issued December 16, 1998, for Technical Specification Amendment No. 217 subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

J. Physical Protection

The licensee 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 the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Millstone, North Anna and Surry Power Stations' Security Plan, Training, and Qualification Plan, Safeguards Contingency Plan, and Independent Spent Fuel Storage Installation Security Program" with revisions submitted through May 15, 2006.

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved Kewaunee, Millstone, North Anna, and Surry Power Stations Cyber Security Plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The CSP was approved by License Amendment No. 276, as supplemented by a change approved by License Amendment No. 286.

K. Deleted by Amendment 227

L. Deleted by Amendment 227

M. Deleted by Amendment 227

N. Deleted by Amendment 203

O. Deleted by Amendment 227

P. Updated Final Safety Analysis Report

(1) The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on July 25, October 1, November 4, and December 2, 2002, describes certain future inspection activities to be completed before the period of extended operation. The licensee shall complete these activities no later than May 25, 2012, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

(2) The Updated Final Safety Analysis Report supplement as revised on July 25, October 1, November 4, and December 2, 2002, shall be included in the next scheduled update to the licensee's Updated Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following the issuance of this renewed license. Until that update is complete, the licensee may make changes to the programs described in such supplement without prior Commission approval, provided that the licensee evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59, and otherwise complies with the requirements in that section.

(3) VEPCO is authorized to revise the Updated Final Safety Analysis Report (UFSAR) to allow implementation of an Alternative GOTHIC Containment Analysis Methodology as set forth in the licensee's application dated October 22, 2007, and as supplemented on November 2, 2007 and November 9, 2007.

Q. Mitigation Strategy

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(1) Fire fighting response strategy with the following elements:

a. Pre-defined coordinated fire response strategy and guidance
b. Assessment of mutual aid fire fighting assets
c. Designated staging areas for equipment and materials
d. Command and control
e. Training of response personnel

(2) Operations to mitigate fuel damage considering the following:

a. Protection and use of personnel assets
b. Communications
c. Minimizing fire spread
d. Procedures for implementing integrated fire response strategy
e. Identification of readily-available pre-staged equipment
f. Training on integrated fire response strategy
g. Spent fuel pool mitigation measures

(3) Actions to minimize release to include consideration of:

a. Water spray scrubbing
b. Dose to onsite responders

R. Deleted by Amendment 313.

S. Deleted by Amendment 313.

T. Deleted by Amendment 313.

U. Deleted by Amendment No. 289

V. The licensee is approved to implement 10 CFR 50.69 using the processes for categorization of Risk-Informed Safety Class (RISC)-1, RISC-2, RISC-3, and RISC-4 structures, systems, and components (SSCs) using: Probabilistic Risk Assessment (PRA) model to evaluate risk associated with internal events, including internal flooding; the Appendix R program to evaluate fire risk; a modified version of the Electric Power Research Institute (EPRI) 3002012988, “Alternative Approaches for Addressing Seismic Risk in 10 CFR 50.69 Risk-Informed Categorization,” Tier 1 approach to assess seismic risk; the shutdown safety assessment process to assess shutdown risk; the Arkansas Nuclear One, Unit 2 (ANO-2) passive categorization method to assess passive component risk for Class 2 and Class 3 SSCs and their associated supports; and a screening of other external hazards updated using the external hazard screening significance process identified in ASME/ANS PRA Standard RA-Sa-2009; as specified in License Amendment No. 301 dated December 8, 2020.

Prior NRC approval, under 10 CFR 50.90, is required for a change to the categorization process specified above (e.g., change from an Appendix R program fire risk evaluation to a fire probabilistic risk assessment approach.)

W. Subsequent Renewed License Conditions

(1) The information in the Updated Final Safety Analysis Report (UFSAR) supplement submitted pursuant to 10 CFR 54.21(d), as revised during the subsequent license renewal application review process, and Virginia Electric and Power Company commitments as listed in Appendix A of the "Safety Evaluation Report Related to the Subsequent License Renewal of Surry Power Station, Units 1 and 2," dated March 2020, are collectively the "Subsequent License Renewal UFSAR Supplement." This Supplement is henceforth part of the UFSAR, which will be updated in accordance with 10 CFR 50.71(e). As such, Virginia Electric and Power Company may make changes to the programs, activities, and commitments described in the Subsequent License Renewal UFSAR Supplement, provided Virginia Electric and Power Company evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59, "Changes, Tests, and Experiments," and otherwise complies with the requirements in that section.

(2) The Subsequent License Renewal UFSAR Supplement, as defined in subsequent renewed license condition (W)(1) above, describes programs to be implemented and activities to be completed prior to the subsequent period of extended operation, which is the period following the May 25, 2032, expiration of the initial renewed license.

a. Virginia Electric and Power Company shall implement those new programs and enhancements to existing programs no later than 6 months before the subsequent period of extended operation.

b. Virginia Electric and Power Company shall complete those activities by the 6-month date prior to the subsequent period of extended operation or by the end of the last refueling outage before the subsequent period of extended operation, whichever occurs later.

c. Virginia Electric and Power Company shall notify the NRC in writing within 30 days after having accomplished item (2)a above and include the status of those activities that have been or remain to be completed in item (2)b above.

4. This subsequent renewed license is effective as of the date of issuance and shall expire at midnight on May 25, 2052.

FOR THE UNITED STATES NUCLEAR REGULATORY COMMISSION

Signed by Veil, Andrea on 05/04/21
Andrea Veil, Director
Office of Nuclear Reactor Regulation

Enclosure:

Appendix A - Technical Specifications for Surry Power Station, Units 1 and 2

Date of Issuance: May 4, 2021

TECHNICAL SPECIFICATIONS
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1.0 DEFINITIONS

The following frequently used terms are defined for the uniform interpretation of the specifications.

A. RATED POWER

A steady state reactor core heat output of 2587 MWt.

B. THERMAL POWER

The total core heat transferred from the fuel to the coolant.

C. REACTOR OPERATION

1. REFUELING SHUTDOWN

When the reactor is subcritical by at least 5% $\Delta k/k$ and T_{avg} is $\leq 140°F$ and fuel is scheduled to be moved to or from the reactor core.

2. COLD SHUTDOWN

When the reactor is subcritical by at least 1% $\Delta k/k$ and T_{avg} is $\leq 200°F$.

3. INTERMEDIATE SHUTDOWN

When the reactor is subcritical by at least 1.77% $\Delta k/k$ and $200°F < T_{avg} < 547°F$.

4. HOT SHUTDOWN

When the reactor is subcritical by at least 1.77% $\Delta k/k$ and T_{avg} is $\geq 547°F$.

5. REACTOR CRITICAL

When the neutron chain reaction is self-sustaining and $k_{eff} = 1.0$.

6. POWER OPERATION

When the reactor is critical and the neutron flux power range instrumentation indicates greater than 2% of rated power.

7. REFUELING OPERATION

Any operation involving movement of core components when the vessel head is unbolted or removed.

D. OPERABLE

A system, subsystem, train, component, or device shall be operable or have operability when it is capable of performing its specified function(s). Implicit in this definition shall be the assumption that all necessary attendant instrumentation, controls, normal and emergency electrical power sources, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s). The system or component shall be considered to have this capability when: (1) it satisfies the limiting conditions for operation defined in Section 3, and (2) it has been tested periodically in accordance with Section 4 and meets its performance requirements.

E. PROTECTIVE INSTRUMENTATION LOGIC

1. ANALOG CHANNEL

An arrangement of components and modules as required to generate a single protective action digital signal when required by a unit condition. An analog channel loses its identity when single action signals are combined.

2. AUTOMATIC ACTUATION LOGIC

A group of matrixed relay contacts which operate in response to the digital output signals from the analog channels to generate a protective action signal.

F. INSTRUMENTATION SURVEILLANCE

1. CHANNEL CHECK

The qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrumentation on channels measuring the same parameter.

2. CHANNEL FUNCTIONAL TEST

Injection of a simulated signal into an analog channel as close to the sensor as practicable or makeup of the logic combinations in a logic channel to verify that it is operable, including alarm and/or trip initiating action.

3. CHANNEL CALIBRATION

Adjustment of channel output such that it responds, with acceptable range and accuracy, to known values of the parameter which the channel measures. Calibration shall encompass the entire channel, including equipment action, alarm, or trip, and shall be deemed to include the CHANNEL FUNCTIONAL TEST.

G. CONTAINMENT INTEGRITY

Containment integrity shall exist when:

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

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

2) Closed by at least one closed manual valve, blind flange, or deactivated automatic valve secured in its closed position except as provided in Specification 3.8.C. Non-automatic or deactivated automatic containment isolation valves may be opened intermittently for operational activities provided that the valves are under administrative control and are capable of being closed immediately, if required.

b. The equipment access hatch is closed and sealed.

c. Each airlock is OPERABLE except as provided in Specification 3.8.B.

d. The containment leakage rates are within the limits of Specification 4.4.

e. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O-rings) is OPERABLE.

H. REPORTABLE EVENT

A reportable event shall be any of those conditions specified in Section 50.73 of 10 CFR Part 50.

I. QUADRANT POWER TILT

The quadrant power tilt is defined as the ratio of the maximum upper excore detector current to the average of the upper excore detector currents or the ratio of the maximum lower excore detector current to the average of the lower excore detector currents whichever is greater. If one excore detector is out of service, the three in-service units are used in computing the average.

J. LOW POWER PHYSICS TESTS

Low power physics tests conducted below 5% of rated power which measure fundamental characteristics of the core and related instrumentation.

K. FIRE SUPPRESSION WATER SYSTEM

A fire suppression water system shall consist of: a water source(s), gravity tank(s) or pump(s), and distribution piping with associated sectionalizing control or isolation valves. Such valves shall include yard hydrant curb valves, and the first valve ahead of the water flow alarm device on each sprinkler, hose standpipe, or spray system riser.

L. OFFSITE DOSE CALCULATION MANUAL (ODCM)

An Offsite Dose Calculation Manual (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/Trip Setpoints, and in the conduct of the Radiological Environmental Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Programs required by Section 6.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.6.B.2 and 6.6.B.3.

M. DOSE EQUIVALENT I-131

DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries per gram) that alone would produce the same dose when inhaled as the combined activities of iodine isotopes I-131, I-132, I-133, I-134, and I-135 actually present. The determination of DOSE EQUIVALENT I-131 shall be performed using Committed Effective Dose Equivalent (CEDE) dose conversion factors from Table 2.1 of EPA Federal Guidance Report No. 11.

N. GASEOUS RADWASTE TREATMENT SYSTEM

A gaseous radwaste treatment system is any system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

O. PROCESS CONTROL PROGRAM (PCP)

The process control program shall contain the current formula, sampling, analyses, tests, and determinations to be made to ensure that the processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, and other requirements governing the disposal of the waste.

P. PURGE - PURGING

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

Q. VENTILATION EXHAUST TREATMENT SYSTEM

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

R. VENTING

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

S. SITE BOUNDARY

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

T. UNRESTRICTED AREA

An unrestricted area shall be any area at or beyond the site boundary where access is not controlled by the licensee for purpose of protection of individuals from exposure to radiation and radioactive materials or any area within the site boundary used for residential qauarters or for industrial, commerical, institutional, or recreational purposes.

U. MEMBER(S) OF THE PUBLIC

Member(s) of the public shall include all individuals who by virtue of their occupational status have no formal association with the plant. This category shall include non-employees of the licensee who are permitted to use portions of the site for recreational, occupational, or other purposes not associated with plant functions. This category shall not include non-employees such as vending machine servicemen or postmen who, as part of their formal job function, occasionally enter an area that is controlled by the licensee for purposes of protection of individuals from exposure to radiation and radioactive materials.

V. CORE OPERATING LIMITS REPORT

The Core Operating Limits Report is the unit 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 Specification 6.2.C. Plant operation within these limits is addressed in individual specifications.

W. STAGGERED TEST BASIS

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.

X. LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank,;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known to not interfere with the operation of leakage detection systems, or;

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE).

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE, and

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a fault in an RCS component body, pipe wall, or vessel wall. LEAKAGE past seals, packing, and gaskets is not pressure boundary LEAKAGE.

Y. DOSE EQUIVALENT XE-133

DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138 actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, "External Exposure to Radionuclides in Air, Water, and Soil."

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMIT, REACTOR CORE

Applicability

Applies to the limiting combinations of THERMAL POWER, Reactor Coolant System pressure, coolant temperature and coolant flow when a reactor is critical.

Objective

To maintain the integrity of the fuel cladding.

Specification

A. The combination of reactor THERMAL POWER level, pressurizer pressure, and Reactor Coolant System (RCS) highest loop average temperature shall not:

1. Exceed the limits specified in the CORE OPERATING LIMITS REPORT when full flow from three reactor coolant pumps exists, and the following Safety Limits shall not be exceeded:

    a. The design limit for departure from nucleate boiling ratio (DNBR) shall be maintained $\geq$ 1.27 for transients analyzed using the Statistical DNBR Evaluation Methodology and the WRB-1 DNB correlation. For transients analyzed using the deterministic methodology, the DNBR shall be maintained greater than or equal to the applicable DNB correlation limit ($\geq$ 1.17 for WRB-1, $\geq$ 1.30 for W-3, $\geq$ 1.14 for ABB-NV).

    b. The peak fuel centerline temperature shall be maintained < 5080°F, decreasing by 9°F per 10,000 MWD/MTU of burnup.

2. The reactor THERMAL POWER level shall not exceed 118% of rated power.

B. In the event the Safety Limit is violated, the facility shall be placed in at least HOT SHUTDOWN within 1 hour. The safety limit is exceeded if the combination of RCS highest loop average temperature and THERMAL POWER level is at any time above the appropriate pressure line as specified in the CORE OPERATING LIMITS REPORT; or the core THERMAL POWER exceeds 118% of the rated power.

Basis

To maintain the integrity of the fuel cladding and prevent fission product release, it is necessary to prevent overheating of the cladding under all operating conditions. This is accomplished by operating within the nucleate boiling regime of heat transfer, wherein the heat transfer coefficient is very large and the clad surface temperature is only a few degrees Fahrenheit above the reactor coolant saturation temperature. The upper boundary of the nucleate boiling regime is termed Departure From Nucleate Boiling (DNB) and at this point there is a sharp reduction of the heat transfer coefficient, which would result in high clad temperatures and the possibility of clad failure. DNB is not, however, an observable parameter during reactor operation. Therefore, DNB has been correlated to thermal power, reactor coolant temperature and reactor coolant pressure which are observable parameters. This correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, DNBR, defined as the ratio of the DNB heat flux at a particular core location to the local heat flux, is indicative of the margin to DNB. The DNB basis is as follows: there must be at least a 95% probability with 95% confidence that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The correlation DNBR limit is based on the entire applicable experimental data set to meet this statistical criterion.(1)

The figure provided in the CORE OPERATING LIMITS REPORT shows the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNBR correlation. The area where clad integrity is assured is below these lines. The temperature limits are considerably more conservative than would be required if they were based upon the design DNBR limit alone but are such that the plant conditions required to violate the limits are precluded by the self-actuated safety valves on the steam generators. The effects of rod bowing are also considered in the DNBR analyses.

The reactor core Safety Limits are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core Safety Limits are used to define the various Reactor Protection System (RPS) functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that the variations in the THERMAL POWER, RCS pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core Safety Limits will be satisfied during steady state operation, normal operational transients, and AOOs.

The Reactor Control and Protection System is designed to prevent any anticipated combination of transient conditions for Reactor Coolant System temperature, pressure and thermal power level that would result in a DNBR less than the design DNBR limit[3] based on steady state nominal operating power levels less than or equal to 100%, steady state nominal operating Reactor Coolant System average temperatures less than or equal to 573.0°F and a steady state nominal operating pressure of 2235 psig. For deterministic DNBR analysis, allowances are made in initial conditions assumed for transient analyses for steady state errors of +2% in power, +4°F in Reactor Coolant System average temperature and ±30 psi in pressure. The combined steady state errors result in the DNB ratio at the start of a transient being 10 percent less than the value at nominal full power operating conditions.

For statistical DNBR analyses, uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95% probability that the minimum DNBR for the limiting rod is greater than or equal to the statistical DNBR limit. The uncertainties in the plant parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty, combined with the correlation DNBR limit, establishes a statistical DNBR limit which must be met in plant safety analyses using values of input parameters without uncertainties. The statistical DNBR limit also ensures that at least 99.9% of the core avoids the onset of DNB when the limiting rod is at the DNBR limit.

The fuel overpower design limit is 118% of rated power. The overpower limit criterion is that core power be prevented from reaching a value at which fuel pellet melting would occur. The value of 118% power allows substantial margin to this limiting criterion. Additional peaking factors to account for local peaking due to fuel rod axial gaps and reduction in fuel pellet stack length have been included in the calculation of this limit.

References

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1) FSAR Section 3.4

2) FSAR Section 3.3

3) FSAR Section 14.2

2.2 SAFETY LIMIT, REACTOR COOLANT SYSTEM PRESSURE

Applicability

Applies to the maximum limit on Reactor Coolant System pressure.

Objective

To maintain the integrity of the Reactor Coolant System.

Specification

A. The Reactor Coolant System pressure shall not exceed 2735 psig with fuel assemblies installed in the reactor vessel.

B. In the event the Safety Limit is violated, the facility shall be placed in at least HOT SHUTDOWN within 1 hour.

Basis

The Reactor Coolant System(1) serves as a barrier which prevents radionuclides contained in the reactor coolant from reaching the environment. In the event of a fuel cladding failure the Reactor Coolant System is the primary barrier against the release of fission products. The maximum transient pressure allowable in the Reactor Coolant System pressure vessel under the ASME Code, Section III is 110% of design pressure. The maximum transient pressure allowable in the Reactor Coolant System piping, valves and fittings under USAS Section B31.1 is 120% of design pressure. Thus, the safety limit of 2735 psig (110% of design pressure) has been established.(2)

The nominal settings of the power-operated relief valves at 2335 psig, the reactor high pressure trip at 2380 psig and the safety valves at 2485 psig are established to assure never reaching the Reactor Coolant System pressure safety limit. The initial hydrostatic test has been conducted at 3107 psig to assure the integrity of the Reactor Coolant System.

1) UFSAR Section 4
2) UFSAR Section 4.3

2.3 LIMITING SAFETY SYSTEM SETTINGS, PROTECTIVE INSTRUMENTATION

Applicability

Applies to trip and permissive settings for instruments monitoring reactor power; and reactor coolant pressure, temperature, and flow; and pressurizer level.

Objective

To provide for automatic protective action in the event that the principal process variables approach a safety limit.

Specification

A. Protective instrumentation settings for reactor trip shall be as follows:

1. Startup Protection

   (a) High flux, power range (low set point) - ≤ 25% of rated power.

   (b) High flux, intermediate range (high set point) - current equivalent to ≤ 40% of full power.

   (c) High flux, source range (high set point) - Neutron flux ≤ 1.51×10^5 counts/sec.

2. Core Protection

   (a) High flux, power range (high set point) - ≤ 109% of rated power.

(b) High pressurizer pressure - $\leq$ 2380 psig.

(c) Low pressurizer pressure - $\geq$ 1875 psig.

(d) Overtemperature ΔT

$$\Delta T \leq \Delta T_0\left[K_1 - K_2\left(\frac{1+t_1 s}{1+t_2 s}\right)(T - T') + K_3(P - P') - f(\Delta I)\right]$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RATED POWER, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature (T_{avg}), °F.
T' is the nominal T_{avg} at RATED POWER, $\leq$ [*] °F.
P is the measured pressurizer pressure, psig.
P' is the nominal RCS operating pressure, $\geq$ [*]psig.
$K_1 \leq$ [*] $K_2 \geq$ [*]/°F $K_3 \geq$ [*]/psig
$t_1 \geq$ [*] sec $t_2 \leq$ [*] sec
$f(\Delta I)$ = [*] {[*] - ($q_t - q_b$)} when $q_t - q_b <$ [*]% RATED POWER
0 when [*]% RATED POWER $\leq q_t - q_b \leq$ [*]% RATED POWER
[*]{($q_t - q_b$)-[*]} when $q_t - q_b >$ [*]% RATED POWER
Where q_t and q_b are percent RATED POWER in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RATED POWER.

The values denoted with [*] are specified in the CORE OPERATING LIMITS REPORT.

The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 2.0% of the ΔT span. (Note that 2.0% of the ΔT span is equal to 3.0% ΔT Power.)

(e) Overpower ΔT

$$\Delta T \leq \Delta T_0\left[K_4 - K_5\left(\frac{t_3 s}{1+t_3 s}\right)T - K_6(T - T') - f(\Delta I)\right]$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RATED POWER, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature (T_{avg}), °F.
T' is the nominal T_{avg} at RATED POWER, ≤ [*] °F.

$K_4 \leq$ [*]	$K_5 \geq$ [*]/°F for decreasing T_{avg}	$K_6 \geq$ [*]/°F when T > T'
	[*] / °F for increasing T_{avg}	[*]/°F when T ≤ T'

$t_3 \geq$ [*] sec
$f(\Delta I)$ = [*]

The values denoted with [*] are specified in the CORE OPERATING LIMITS REPORT.

The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 2.0% of the ΔT span. (Note that 2.0% of the ΔT span is equal to 3.0% of ΔT Power.)

(f) Low reactor coolant loop flow - ≥ 91% of normal indicated loop flow as measured at elbow taps in each loop

(g) Low reactor coolant pump motor frequency - ≥ 57.5 Hz

(h) Reactor coolant pump under voltage - ≥ 70% of normal voltage

3. Other reactor trip settings

(a) High pressurizer water level - ≤ 89.12% of span

(b) Low-low steam generator water level - ≥ 16% of narrow range instrument span

(c) Low steam generator water level - ≥ 19% of narrow range instrument span in coincidence with steam/feedwater mismatch flow - ≤ 1.0×10^6 lbs/hr

(d) Turbine trip

(e) Safety injection - Trip settings for Safety Injection are detailed in TS Section 3.7.

B. Protective instrumentation settings for reactor trip interlocks shall be as follows:

1. The reactor trip on low pressurizer pressure, high pressurizer level, turbine trip, and low reactor coolant flow for two or more loops shall be unblocked prior to or when power increases to 11% of rated power.

2. The single loop loss of flow reactor trip shall be unblocked prior to or when the power range nuclear flux increases to 37% of rated power.

3. The power range high flux, low setpoint trip and the intermediate range high flux, high setpoint trip shall be unblocked prior to or when power decreases to 7% of rated power.

4. The source range high flux, high setpoint trip shall be unblocked prior to or when the intermediate range nuclear flux decreases to 5×10^{-11} amperes.

Basis

The power range reactor trip low setpoint provides protection in the power range for a power excursion beginning from low power. This trip value was used in the safety analysis.(1) The Source Range High Flux Trip provides reactor core protection during shutdown (COLD SHUTDOWN, INTERMEDIATE SHUTDOWN, and HOT SHUTDOWN) when the reactor trip breakers are closed and reactor power is below the permissive P-6. The Source and Intermediate Range trips in addition to the Power Range trips provide core protection during reactor startup when the reactor is critical. The Source Range channels will initiate a reactor trip at about 1.51×10^5 counts per second unless manually blocked when P-6 becomes active. The Intermediate Range channels will initiate a reactor trip at a current level proportional to ≤ 40% of RATED POWER unless manually blocked when P-10 becomes active. In the accident analyses, bounding transient analysis results are based on reactivity excursions from an initially critical condition, where the Source Range trip is assumed to be blocked. Accidents initiated form a subcritical condition would produce less severe results, since the Source Range trip would provide core protection at a lower power level. No credit is taken for operation of the Intermediate Range High Flux trip. However, its functional capability is required by this specification to enhance the overall reliability of the Reactor Protection System.

The high and low pressurizer pressure reactor trips limit the pressure range in which reactor operation is permitted. The high pressurizer pressure reactor trip is also a backup to the pressurizer code safety valves for overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The low pressurizer pressure reactor trip also trips the reactor in the unlikely event of a loss-of-coolant accident.(3)

The overtemperature ΔT reactor trip provides core protection against DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided only that the transient is slow with respect to piping transit delays from the core to the temperature detectors (about 3 seconds), and pressure is within the range between high and low pressure reactor trips. With normal axial power distribution, the reactor trip limit, with allowance for errors,(2) is always below the core safety limit as specified in the CORE OPERATING LIMITS REPORT. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the reactor limit is automatically reduced.(4)(5)

The overpower and overtemperature protection system setpoints have been revised to include effects of fuel densification on core safety limits and to apply to 100% of design flow. The revised setpoints in the Technical Specifications will ensure that the combination of power, temperature, and pressure will not exceed the revised core safety limits as specified in the CORE OPERATING LIMITS REPORT. The reactor is prevented from reaching the overpower limit condition by action of the nuclear overpower and overpower ΔT trips. The overpower limit criteria is that core power be prevented from reaching a value at which fuel pellet centerline melting would occur. The overpower protection system set points include the effects of fuel densification.

The overpower ΔT reactor trip prevents power density anywhere in the core from exceeding 118% of design power density as discussed Section 7 and specified in Section 14.2.2 of the FSAR and includes corrections for axial power distribution, change in density and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors. The specified setpoints meet this requirement and include allowance for instrument errors.(2)

Refer to Technical Report EE-0116 for justification of the dynamic limits (time constants) for the Overtemperature ΔT and Overpower ΔT Reactor Trip functions.

The low flow reactor trip protects the core against DNB in the event of a sudden loss of power to one or more reactor coolant pumps. The undervoltage reactor trip protects against a decrease in Reactor Coolant System flow caused by a loss of voltage to the reactor coolant pump busses. The underfrequency reactor trip (opens RCP supply breakers and) protects against a decrease in Reactor Coolant System flow caused by a frequency decay on the reactor coolant pump busses. The undervoltage and underfrequency reactor trips are expected to occur prior to the low flow trip setpoint being reached for low flow events caused by undervoltage or underfrequency, respectively. The accident analysis conservatively ignores the undervoltage and underfrequency trips and assumes reactor protection is provided by the low flow trip. The undervoltage and underfrequency reactor trips are retained as backup protection.

The high pressurizer water level reactor trip protects the pressurizer safety valves against water relief. Approximately 1125 ft^3 of water corresponds to 89.12% of span. The specified setpoint allows margin for instrument error(7) and transient level overshoot beyond this trip setting so that the trip function prevents the water level from reaching the safety valves.

The low-low steam generator water level reactor trip protects against loss of feedwater flow accidents. The specified setpoint assures that there will be sufficient water inventory in the steam generators at the time of trip to allow for starting delays for the Auxiliary Feedwater System.(7)

The specified reactor trips are blocked at low power where they are not required for protection and would otherwise interfere with normal unit operations. The prescribed setpoint above which these trips are unblocked assures their availability in the power range where needed.

Above 11% power, an automatic reactor trip will occur if two or more reactor coolant pumps are lost. Above 37%, an automatic reactor trip will occur if any pump is lost or de-energized. This latter trip will prevent the minimum value of the DNBR from going below the applicable design as a result of the decrease of Reactor Coolant System flow associated with the loss of a single reactor coolant pump.

Although not necessary for core protection, other reactor trips provide additional protection. The steam/feedwater flow mismatch which is coincident with a low steam generator water level is designed for and provides protection from a sudden loss of the reactor's heat sink. Upon the actuation of the safety injection circuitry, the reactor is tripped to decrease the severity of the accident condition. Upon turbine trip, at greater than 11% power, the reactor is tripped to reduce the severity of the ensuing transient.

Permissive P-7 is made up of input signals from Turbine First Stage Pressure and NIS Power Range. Signals to the P-7 and P-10 permissives are supplied from the same bistables in the NIS Power Range drawers. P-7 and P-10 will both enable and block functions from the "trip" and "reset" points of these bistables. The calibration procedures for the NIS Power Range bistables set the nominal trip setpoints associated with the two permissives such that they will trip whenever the measured reactor power level reaches 10% power (increasing). When two out of four of the NIS Power Range channels trip or if one of the two Turbine First Stage Pressure channels trip the following occurs:

- Permissive P-7 allows reactor trip on the following: low flow, reactor coolant pump breakers open in more than one loop, undervoltage (RCP busses), underfrequency (RCP busses), turbine trip, pressurizer low pressure, and pressurizer high pressure.
- Permissive P-10 allows manual block of intermediate range reactor trip, allows manual block of power range (low setpoint) reactor trip, allows manual block of intermediate range rod stop (P-1), and automatically blocks source range reactor trip (P-6) and provides an input to P-7.

The "trip" and "reset" of a bistable cannot be the same point. It is physically not possible. There must be a deadband between the "trip" and "reset" points. The calibration procedures for the NIS Power Range bistables set the nominal reset points for the two permissives such that they reset whenever the measured reactor power level reaches 8% power (decreasing). The P-7 input from Turbine First Stage Pressure is set to reset at 8.8% Turbine Load (decreasing). When three out of four of the NIS Power Range channels reset or if two out of the two Turbine First Stage Pressure channels reset the following occurs:

- Permissive P-7 blocks reactor trip on the following: low flow, reactor coolant pump breakers open in more than one loop, undervoltage, underfrequency, turbine trip, pressurizer low pressure, and pressurizer high pressure.

When three out of four of the NIS Power Range channels reset the following occurs:

- Permissive P-10 defeats automatically the manual block of intermediate range reactor trip, defeats automatically the manual block of power range (low setpoint) reactor trip, and defeats automatically the manual block of intermediate range rod stop (P-1).

There are no specific Safety Analysis Limits associated with Permissives P-7 and P-10. However, they are "Assumed Available" by Nuclear Analysis and Fuel. Since P-7 and P-10 are permissives for functions with Safety Analysis Limits, for conservatism, they will be treated as if they had a Limiting Safety System Setting. In order to account for instrumentation errors, 1% of reactor power is added to the P-7 and P-10 safety functions. This results in a Limiting Safety System Setting for the P-7 enable interlock of 11% of reactor power. The Limiting Safety System Setting for the P-10 (defeat block) interlock is 7% of reactor power.

The methodology for determining the Limiting Safety System Settings (LSSS) found in TS 2.3 was developed in Technical Report EE-0116. The Limiting Safety System Setting must be chosen so that automatic protective action will correct an abnormal situation before the safety limit is exceeded. At Surry Power Station the Allowable Value (AV) serves as the Limiting Safety System Setting such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the Channel Functional Test (which is also referred to as the Channel Operational Test or COT). As such, the Allowable Value differs from the Trip Setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that the Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

Technical Report EE-0116 verifies that Surry's methodology for determining Allowable Values is in agreement with the intent of ISA Standard S67.04, Methods 1 and 2. In addition, it is Dominion's position that the Analytical Limit will be protected if:

1. the distance between the Trip Setpoint and the Analytical Limit is equal to or greater than the Total Loop Uncertainty for that channel <u>and</u>

2. the distance between the Allowable Value and the Analytical Limit is equal to or greater than the non-COT error components of the Total Loop Uncertainty <u>and</u>

3. the distance between the Trip Setpoint and the Allowable Value is equal to the COT error components of the Total Loop Uncertainty without any excessive margin included.

Both the Trip Setpoint and the Allowable Value must be properly established in order to adequately protect the Analytical Limit.

References

(1) UFSAR Section 14.2.1

(2) UFSAR Section 14.2

(3) UFSAR Section 14.5

(4) UFSAR Section 7.2

(5) UFSAR Section 3.2.2

(6) UFSAR Section 14.2.9

(7) UFSAR Section 7.2

3.0 LIMITING CONDITIONS FOR OPERATION

3.0.1 In the event a Limiting Condition for Operation and/or associated modified requirements cannot be satisfied because of circumstances in excess of those addressed in the specification, the unit shall be placed in at least hot shutdown within 6 hours and in at least cold shutdown within the following 30 hours unless corrective measures are completed that permit operation under the permissible action statements for the specified time interval as measured from initial discovery or until the reactor is placed in a condition in which the specification is not applicable. Exceptions to these requirements shall be stated in the individual specifications.

3.0.2 When a system, subsystem, train, component or device is determined to be inoperable solely because its emergency power source is inoperable, or solely because its normal power source is inoperable, it may be considered operable for the purpose of satisfying the requirements of its applicable Limiting Condition for Operation, provided: (1) its corresponding normal or emergency power source is operable; and (2) all of its redundant system(s), subsystem(s), train(s), component(s) and device(s) are operable, or likewise satisfy the requirements of this specification. Unless both conditions (1) and (2) are satisfied, the unit shall be placed in at least hot shutdown within 6 hours and in at least cold shutdown within the following 30 hours. This specification is not applicable in cold shutdown or refueling shutdown conditions.

Basis

3.0.1 This specification delineates the action to be taken for circumstances not directly provided for in the action statements and whose occurrence would violate the intent of the specification. For example, Specification 3.3 requires each Reactor Coolant System accumulator to be operable and provides explicit action requirements if one accumulator is inoperable. Under the terms of Specification 3.0.1, if more than one accumulator is inoperable, the unit is required to be in at least hot shutdown within 6 hours. As a further example, Specification 3.4 requires two Containment Spray Subsystems to be operable and provides explicit action requirements if one spray system is inoperable. Under the terms of Specification 3.0.1, if both of the required Containment Spray Subsystems are inoperable, the unit is required to be in at least hot shutdown within 6 hours and in at least cold shutdown in the next 30 hours. It is assumed that the unit is brought to the required condition within the required times by promptly initiating and carrying out the appropriate action.

3.0.2 This specification delineates what additional conditions must be satisfied to permit operation to continue, consistent with the actions for power sources, when a normal or emergency power source is not operable. It specifically prohibits operation when one division is inoperable because its normal or emergency power source is inoperable and a system, subsystem, train, component or device in another division is inoperable for another reason.

The provisions of this specification permit the action statements associated with individual systems, subsystems, trains, components or devices to be consistent with the action statements of the associated electrical power source. It allows operation to be governed by the time limits of the action statement associated with the Limiting Condition for Operation for the normal or emergency power source, not the individual action statements for each system, subsystem, train, component or device that is determined to be inoperable solely because of the inoperability of its normal or emergency power source.

For example, Specification 3.16 requires in part that two emergency diesel generators be operable. The action statement provides for out-of-service time when one emergency diesel generator is not operable. If the definition of operable were applied without consideration of Specification 3.0.2, all systems, subsystems, trains, components and devices supplied by the inoperable emergency power source would also be inoperable. This would dictate invoking the applicable action statements for each of the applicable Limiting Conditions for Operation. However, the provisions of Specification 3.0.2 permit the time limits for continued operation to be consistent with the action statement for the inoperable emergency diesel generator instead, provided the other specified conditions are satisfied. In this case, this would mean that the corresponding normal power source must be operable, and all redundant systems, subsystems, trains, components and devices must be operable, or otherwise satisfy Specification 3.0.2 (i.e., be capable of performing their design function and have at least one normal or one emergency power source operable). If they are not satisfied, shutdown is required in accordance with this specification.

As a further example, Specification 3.16 requires in part that two physically independent circuits between the offsite transmission network and the onsite Class IE distribution system be operable. The action statement provides out-of-service time when one required offsite circuit is not operable. If the definition of operable were applied without consideration of Specification 3.0.2, all systems, subsystems, trains, components and devices supplied by the inoperable normal power source, one of the offsite circuits, would be inoperable. This would dictate invoking the applicable action statements for each of the applicable LCOs. However, the provisions of Specification 3.0.2 permit the time limits for continued operation to be consistent with the action statement for the inoperable normal power source instead, provided the other specified conditions are satisfied. In this case, this would mean that for one division the emergency power source must be operable (as must be the components supplied by the emergency power source) and all redundant systems, subsystems, trains, components and devices in the other division must be operable, or likewise satisfy Specification 3.0.2 (i.e., be capable of performing their design functions and have an emergency power source operable). In other words, both emergency power sources must be operable and all redundant systems, subsystems, trains, components and devices in both divisions must also be operable. If these conditions are not satisfied, shutdown is required in accordance with this specification.

In cold shutdown or refueling shutdown conditions, Specification 3.0.2 is not applicable, and thus the individual action statements for each applicable Limiting Condition for Operation in these conditions must be adhered to.

3.1 REACTOR COOLANT SYSTEM

Applicability

Applies to the operating status of the Reactor Coolant System.

Objectives

To specify those limiting conditions for operation of the Reactor Coolant System which must be met to ensure safe REACTOR OPERATION.

These conditions relate to: operational components, heatup and cooldown, leakage, reactor coolant activity, oxygen and chloride concentrations, minimum temperature for criticality, and Reactor Coolant System overpressure mitigation.

A. Operational Components

Specifications

1. Reactor Coolant Pumps

    a. A reactor shall not be brought critical with less than three pumps, in non-isolated loops, in operation.

b. If an unscheduled loss of one or more reactor coolant pumps occurs while operating below 11% RATED POWER (P-7) and results in less than two pumps in service, the affected plant shall be shutdown and the reactor made subcritical by inserting all control banks into the core. The shutdown rods may remain withdrawn.

c. When the average reactor coolant loop temperature is greater than 350°F, the following conditions shall be met:

   1. At least two reactor coolant loops shall be OPERABLE.

   2. At least one reactor coolant loop shall be in operation.

d. When the average reactor coolant loop temperature is less than or equal to 350°F, the following conditions shall be met:

   1. A minimum of two non-isolated loops, consisting of any combination of reactor coolant loops or residual heat removal loops, shall be OPERABLE, except as specified below:

      (a) One RHR loop may be inoperable for up to 2 hours for surveillance testing provided the other RHR loop is OPERABLE and in operation.

      (b) During REFUELING OPERATIONS the residual heat removal loop may be removed from operation as specified in TS 3.10.A.4.

   2. At least one reactor coolant loop or one residual heat removal loop shall be in operation, except as specified in Specification 3.10.A.4.

e. When all three pumps have been idle for > 15 minutes, the first pump shall not be started unless: (1) a bubble exists in the pressurizer or (2) the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

2. Steam Generator

A minimum of two steam generators in non-isolated loops shall be OPERABLE when the average Reactor Coolant System temperature is greater than 350°F.

3. Pressurizer Safety Valves

a. Three valves shall be OPERABLE when the head is on the reactor vessel and the Reactor Coolant System average temperature is greater than 350°F, the reactor is critical, or the Reactor Coolant System is not connected to the Residual Heat Removal System.

b. Valve lift settings shall be maintained at 2485 psig ± 1 percent*

* The as-found tolerance shall be ±3% and the as-left tolerance shall be ±1%.

4. Reactor Coolant Loops

   a. Loop stop valves shall not be closed in more than one loop unless the Reactor Coolant System is connected to the Residual Heat Removal System and the Residual Heat Removal System is OPERABLE.

   b. POWER OPERATION with less than three loops in service is prohibited. The following loop isolation valves shall have AC power removed and their breakers locked, sealed or otherwise secured in the open position during POWER OPERATION:

<u>Unit No. 1</u>	<u>Unit No. 2</u>
MOV 1590	MOV 2590
MOV 1591	MOV 2591
MOV 1592	MOV 2592
MOV 1593	MOV 2593
MOV 1594	MOV 2594
MOV 1595	MOV 2595

5. Pressurizer

   a. The reactor shall be maintained subcritical by at least 1% until the steam bubble is established and the necessary sprays and at least 125 KW of heaters are operable.

   b. With the pressurizer inoperable due to inoperable pressurizer heaters, restore the inoperable heaters within 72 hours or be in at least HOT SHUTDOWN within 6 hours and the Reactor Coolant System temperature and pressure less than 350°F and 450 psig, respectively, within the following 12 hours.

   c. With the pressurizer otherwise inoperable, be in at least HOT SHUTDOWN with the reactor trip breakers open within 6 hours and the Reactor Coolant System temperature and pressure less than 350°F and 450 psig, respectively, within the following 12 hours.

6. Relief Valves

Two power operated relief valves (PORVs) and their associated block valves shall be OPERABLE* whenever the Reactor Coolant System average temperature is ≥ 350°F.

a. With one or both PORVs inoperable but capable of being manually cycled, within 1 hour either restore the PORV(s) to OPERABLE status or close the associated block valve(s) and maintain power to the associated block valve(s). Otherwise, be in at least HOT SHUTDOWN within the next 6 hours and reduce Reactor Coolant System average temperature to < 350°F within the following 6 hours.

b. With one PORV inoperable and not capable of being manually cycled, within 1 hour either restore the PORV to OPERABLE status or capable of being manually cycled or close the associated block valve and remove power from the block valve. In addition, restore the PORV to OPERABLE status or capable of being manually cycled within the following 72 hours. Otherwise, be in at least HOT SHUTDOWN within the next 6 hours and reduce Reactor Coolant System average temperature to < 350°F within the following 6 hours.

c. With both PORVs inoperable and not capable of being manually cycled, within 1 hour restore at least 1 PORV to OPERABLE status or capable of being manually cycled. Otherwise, close the associated block valves and remove power from the block valves. In addition, be in HOT SHUTDOWN within the next 6 hours and reduce Reactor Coolant System average temperature to < 350°F within the following 6 hours.

* Automatic actuation capability may be blocked when Reactor Coolant System pressure is below 2010 psig.

d. With one block valve inoperable, within 1 hour either restore the block valve to OPERABLE status or place the associated PORV in manual. In addition, restore the block valve to OPERABLE status in the next 72 hours or, be in at least HOT SHUTDOWN within the next 6 hours and reduce reactor coolant average temperature to <350°F within the following 6 hours.

e. With both block valves inoperable, within 1 hour either restore the block valves to OPERABLE status or place the associated PORVs in manual. Restore at least 1 block valve to OPERABLE status within the next hour or, be in at least HOT SHUTDOWN within the next 6 hours and reduce reactor coolant average temperature to <350°F within the following 6 hours.

f. With one or both PORV(s) inoperable (but capable of being manually cycled) because of an inoperable backup air supply, within 14 days either restore the PORV(s) backup air supply(ies) to OPERABLE status or be in at least HOT SHUTDOWN within the next 6 hours and reduce Reactor Coolant System average temperature to < 350°F within the following 6 hours.

7. Reactor Vessel Head Vents

a. At least two Reactor Vessel Head vent paths consisting of two isolation valves in series powered from emergency buses shall be OPERABLE and closed whenever RCS temperature and pressure are >350°F and 450 psig.

b. With one Reactor Vessel Head vent path inoperable; startup and/or power operation may continue provided the inoperable vent path is maintained closed with power removed from the valve actuator of both isolation valves in the inoperable vent path.

c. With two Reactor Vessel Head vent paths inoperable; maintain the inoperable vent path closed with power removed from the valve actuator of all isolation valves in the inoperable vent paths, and restore at least one of the vent paths to operable status within 30 days or be in hot shutdown within 6 hours and in cold shutdown within the following 30 hours.

Basis

Specification 3.1.A-1 requires that a sufficient number of reactor coolant pumps be operating to provide coastdown core cooling flow in the event of a loss of reactor coolant flow accident. This provided flow will maintain the DNBR above the applicable design limit.(1) Heat transfer analyses also show that reactor heat equivalent to approximately 10% of rated power can be removed with natural circulation; however, the plant is not designed for critical operation with natural circulation or one loop operation and will not be operated under these conditions.

When the boron concentration of the Reactor Coolant System is to be reduced, the process must be uniform to prevent sudden reactivity changes in the reactor. Mixing of the reactor coolant will be sufficient to maintain a uniform concentration if at least one reactor coolant pump or one residual heat removal pump is running while the change is taking place. The residual heat removal pump will circulate the equivalent of the reactor coolant system volume in approximately one half hour.

One steam generator capable of performing its heat transfer function will provide sufficient heat removal capability to remove core decay heat after a normal reactor shutdown. The requirement for redundant coolant loops ensures the capability to remove core decay heat when the Reactor Coolant System average temperature is less than or equal to 350°F. Because of the low-low steam generator water level reactor trip, normal reactor criticality cannot be achieved without water in the steam generators in reactor coolant loops with open loop stop valves. The requirement for two OPERABLE steam generators, combined with the requirements of Specification 3.6, ensure adequate heat removal capabilities for Reactor Coolant System temperatures of greater than 350°F.

Each of the pressurizer safety valves is designed to relieve 295,000 lbs. per hr. of saturated steam at the valve setpoint. Two safety valves have a capacity greater than the maximum surge rate resulting from complete loss of load.(2)

The limitation specified in item 4 above on reactor coolant loop isolation will prevent an accidental isolation of all the loops which would eliminate the capability of dissipating core decay heat when the Reactor Coolant System is not connected to the Residual Heat Removal System.

The requirement for steam bubble formation in the pressurizer when the reactor passes 1% subcriticality will ensure that the Reactor Coolant System will not be solid when criticality is achieved.

The requirement that 125 Kw of pressurizer heaters and their associated controls be capable of being supplied electrical power from an emergency bus provides assurance that these heaters can be energized during a loss of offsite power condition to maintain natural circulation at HOT SHUTDOWN.

The power operated relief valves (PORVs) operate to relieve Reactor Coolant System pressure below the setting of the pressurizer code safety valves. The PORVs and their associated block valves may be used by the unit operators to depressurize the Reactor Coolant System to recover from certain transients if normal pressurizer spray is not available. Specifically, cycling of the PORVs is required to mitigate the consequences of a design basis steam generator tube rupture accident. Therefore, whenever a PORV is inoperable, but capable of being manually cycled, the associated block valve will be closed with its power maintained. The capability to cycle the PORVs is verified during each refueling outage (and is not required during power operations). These relief valves have remotely operated block valves to provide a positive shutoff capability should a relief valve leak excessively. The electrical power for both the relief valves and the block valves is supplied from an emergency power source to ensure the ability to seal this possible Reactor Coolant System leakage path.

With one or both PORVs inoperable (but capable of being manually cycled) due to an inoperable backup air supply, continued operation for 14 days is allowed provided the normal motive force for the PORVs, i.e., the instrument air system, continues to be available. Instrument air has a high system reliability, and the likelihood of it being unavailable during a demand for PORV operation is low enough to justify a reasonable length of time (i.e., 14 days) to repair the backup air system.

The accumulation of non-condensable gases in the Reactor Coolant System may result from sudden depressurization, accumulator discharges and/or inadequate core cooling conditions. The function of the Reactor Vessel Head Vent is to remove non-condensable gases from the reactor vessel head. The Reactor Vessel Head Vent is designed with redundant safety grade vent paths. Venting of non-condensable gases from the pressurizer steam space is provided primarily through the Pressurizer PORVs. The pressurizer is, however, equipped with a steam space vent designed with redundant safety grade vent paths.

References

(1) UFSAR Section 14.2.9

(2) UFSAR Section 14.2.10

B. HEATUP AND COOLDOWN

Specification

1. Unit 1 and Unit 2 reactor coolant temperature and pressure and the system heatup and cooldown (with the exception of the pressurizer) shall be limited in accordance with TS Figures 3.1-1 and 3.1-2.

   Heatup:

   Figure 3.1-1 may be used for heatup rates of up to 60°F/hr.

   Cooldown:

   Allowable combinations of pressure and temperature for specific cooldown rates are below and to the right of the limit lines as shown in TS Figure 3.1-2. This rate shall not exceed 100°F/hr. Cooldown rates between those shown can be obtained by interpolation between the curves on Figure 3.1-2.

   Core Operation:

   During operation where the reactor core is in a critical condition (except for low level physics tests), vessel metal and fluid temperature shall be maintained above the reactor core criticality limits specified in 10 CFR 50 Appendix G. The reactor shall not be made critical when the reactor coolant temperature is below the Minimum Temperature for Criticality specified in T.S. 3.1.E.

2. The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the vessel is below 70°F.

3. The pressurizer heatup and cooldown rates shall not exceed 100°F/hr. and 200°F/hr., respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

Basis

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G.

1) The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.1-1 and 3.1-2.

   a) Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation.

   b) Figures 3.1-1 and 3.1-2 define limits to assure prevention of non-ductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

   c) Vacuum-assist fill of the Reactor Coolant System loops in COLD SHUTDOWN or REFUELING SHUTDOWN is an acceptable condition since the resulting pressure/temperature combination is located in the Acceptable Operation region of Figures 3.1-1 and 3.1-2.

2) These limit lines shall be calculated periodically using methods provided below.

3) The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F.

4) The pressurizer heatup and cooldown rates shall not exceed 100°F/hr. and 200°F/hr. respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F.

Although the pressurizer operates in temperature ranges above those for which there is reason for concern of non-ductile failure, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Code requirements.

5) System preservice hydrotests and in-service leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI according to the leak test limit line shown in Figure 3.1-1.

6) The reactor shall not be made critical when the reactor coolant temperature is below the Minimum Temperature for Criticality specified in Technical Specification 3.1.E.

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, ASTM E185-82, and in accordance with additional reactor vessel requirements. These properties are then evaluated in accordance with Appendix G to Section III of the ASME Boiler and Pressure Vessel Code.

Heatup and cooldown limit curves are calculated using a bounding value of the nil-ductility reference temperature, RT_{NDT}, at the end of 68 Effective Full Power Years (EFPY) for Units 1 and 2. The heatup and cooldown limit curves were calculated using the most limiting value of RT_{NDT} (228.4°F) which occurred at the 1/4-T, 0° azimuthal location in the Unit 1 intermediate-to-lower shell circumferential weld. The limiting RT_{NDT} at the 1/4-T location in the core region is greater than the RT_{NDT} of the limiting unirradiated material. This ensures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results are presented in UFSAR Section 4.1. Reactor operation and resultant fast neutron (E greater than 1 MEV) irradiation can cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the copper and nickel content of the material and the fluence was calculated in accordance with the recommendations of Regulatory Guide 1.99, Revision 2 “Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials.” The heatup and cooldown limit curves of Figures 3.1-1 and 3.1-2 include predicted adjustments for this shift in RT_{NDT} at the end of 68 EFPY for Units 1 and 2 (as well as adjustments for location of the pressure sensing instrument).

Surveillance capsules will be removed in accordance with the requirements of ASTM E185-82 and 10 CFR 50, Appendix H. The surveillance specimen withdrawal schedule is shown in the UFSAR. The heatup and cooldown curves must be recalculated when the ΔRT_{NDT} determined from the surveillance capsule exceeds the calculated ΔRT_{NDT} for the equivalent capsule radiation exposure, or when the service period exceeds 68 EFPY for Units 1 and 2 prior to a scheduled refueling outage.

Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Appendix G in Section III of the ASME Boiler and Pressure Vessel Code as required by Appendix G to 10 CFR Part 50.

The general method for calculating heatup and cooldown limit curves is based upon the principles of the linear elastic fracture mechanics (LEFM) technology. In the calculation procedures a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, T, and a length of one and one half T is assumed to exist at the inside of the vessel wall as well as at the outside of the vessel wall. The dimensions of this postulated crack, referred to in Appendix G of ASME Section III as the reference flaw, amply exceed the current capabilities of inservice inspection techniques. Therefore, the reactor operation limit curves developed for this reference crack are conservative and provide sufficient safety margins for protection against non-ductile failure. To assure that the radiation embrittlement effects are accounted for in the calculation of the limit curves, the most limiting value of the nil ductility reference temperature, RT_{NDT}, is used and this includes the radiation-induced shift, ΔRT_{NDT}, corresponding to the end of the period for which heatup and cooldown curves are generated.

The approach for calculating the allowable limit curves for various heatup and cooldown rates in the 1986 Edition of the ASME Code specifies that the total stress intensity factor, K_I, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, K_{IR}, for the metal temperature at that time. K_{IR} is obtained from the reference fracture toughness curve, defined in Appendix G to the ASME Code. The K_{IR} curve is given by the equation:

$$K_{IR} = 26.78 + 1.223 \exp [0.0145(T - RT_{NDT} + 160)] \qquad (1)$$

where K_{IR} is the reference stress intensity factor as a function of the metal temperature T and the metal nil ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\,K_{IM} + K_{It} \leq K_{IR} \qquad (1)$$

where, K_{IM} is the stress intensity factor caused by membrance (pressure) stress.

K_{It} is the stress intensity factor caused by the thermal gradients

K_{IR} is provided by the code as a function of temperature relative to the RT_{NDT} of the material.

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{IR} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding thermal stress intensity factor, K_{It}, for the reference flaw is computed. From Equation (2) the pressure stress intensity factors are obtained and, from these, the allowable pressures are calculated.

The heatup limit curve, Figure 3.1-1, is a composite curve which was prepared by determining the most conservative case, with either the inside or outside wall controlling, for any heatup rate up to 60°F per hour. The cooldown limit curves of Figure 3.1-2 are composite curves which were prepared based upon the same type analysis with the exception that the controlling location is always the inside wall where the cooldown thermal gradients tend to produce tensile stresses while producing compressive stresses at the outside wall. The cooldown limit curves are valid for cooldown rates up to 100°F/hr. The heatup and cooldown curves were prepared based upon the most limiting value of the predicted adjusted reference temperature at the end of 68 EFPY for Units 1 and 2. The adjusted reference temperature was calculated using materials properties data from the B&W Owners Group Master Integrated Reactor Vessel Surveillance Program (MIRVSP) documented in the most recent revision to BAW-1543 and reactor vessel neutron fluence data obtained from plant-specific analyses.

The technical basis for the data points and the associated RT_{NDT} values used to generate the heatup and cooldown curves is provided in WCAP-14177 (Reference 2) and were determined to be applicable to the 48 EFPY period of extended operation under first license renewal. The associated RT_{NDT} values used to calculate the heatup and cooldown curves provided in WCAP-14177 (Revision 2) are based upon the Surry Unit 1 Intermediate to Lower Shell Circ Weld:

1/4-T, 228.4°F and
3/4-T, 189.5°F

The heatup and cooldown curves for operation through 48 EFPY were based upon the K_{Ir} methodology. These heatup and cooldown curves were subsequently evaluated using the K_{1c} methodology for Subsequent License Renewal (SLR) at 68 EFPY in WCAP-18243-NP (Reference 3).

The limiting reactor vessel materials at 68 EFPY were determined to be the Surry Unit 1 Lower Shell Longitudinal Weld L2 at 1/4-T and the Surry Unit 2 Intermediate to Lower Shell Circumferential Weld at 3/4-T. The associated RT_{NDT} values calculated at 68 EFPY are:

1/4-T, 219.4°F and
3/4-T, 179.8°F

The data points and the associated RT_{NDT} values used to generate the heatup and cooldown curves in TS Figures 3.1-1 and 3.1-2, respectively, are conservative based upon use of the K_{Ic} methodology. Therefore, the heatup and cooldown curves did not require revision as a result of SLR. However, the fluence applicability is updated from 48 EFPY to 68 EFPY.

The reactor boltup temperature is defined in 10 CFR 50, Appendix G as "The highest reference temperature of the material in the closure flange region that is highly stressed by the bolt preload." The reactor vessel may be bolted up at a temperature greater than the initial RT_{NDT} of the material stressed by the boltup (e.g., the vessel flange). As noted on Figures 3.1-1 and 3.1-2, the limiting boltup temperature is 10°F. An administrative minimum boltup temperature limit greater than 10°F is imposed in station procedures to ensure the Reactor Coolant System temperatures are sufficiently high to prevent damage to the reactor vessel closure head/vessel flange during the removal or installation of reactor vessel head bolts. The limiting boltup temperature and the administrative minimum boltup temperature limit are in effect when the reactor vessel head bolts are under tension.

References

(1) UFSAR, Section 4.1, Design Bases

(2) WCAP-14177, "Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation," (October 1994)

(3) WCAP-18243, Rev. 2, "Surry Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation," (July 2018)

C. RCS Operational LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever Tavg (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Specifications

1. RCS operational LEAKAGE shall be limited to:

   a. No pressure boundary LEAKAGE,

   b. 1 gpm unidentified LEAKAGE,

   c. 10 gpm identified LEAKAGE, and

   d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

2.a. If pressure boundary LEAKAGE exists, isolate affected component, pipe, or vessel from the RCS by use of a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours.

b. If the pressure boundary LEAKAGE is not isolated as specified within 4 hours, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

3.a. If RCS operational LEAKAGE is not within the limits of 3.1.C.1 for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE, reduce LEAKAGE to within the specified limits within 4 hours.

b. If the LEAKAGE is not reduced to within the specified limits within 4 hours, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

4. If primary to secondary LEAKAGE is not within the limit specified in 3.1.C.1.d, the unit shall be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

5. Detected or suspected leakage from the Reactor Coolant System shall be investigated and evaluated. At least two means shall be available to detect reactor coolant system leakage. One of these means must depend on the detection of radionuclides in the containment.

6.a. Prior to going critical all primary coolant system pressure isolation valves listed below shall be functional as a pressure isolation device, except as specified in 3.1.C.6.b. Valve leakage shall not exceed the amounts indicated.

	Unit 1	Unit 2	Max. Allowable Leakage (see note (a) below)
Loop A, Cold Leg	1-SI-79, 1-SI-241	2-SI-79, 2-SI-241	≤ 5.0 gpm for each valve
Loop B, Cold Leg	1-SI-82, 1-SI-242	2-SI-82, 2-SI-242	
Loop C, Cold Leg	1-SI-85, 1-SI-243	2-SI-85, 2-SI-243	

b. If Specification 3.1.C.6.a cannot be met, an orderly shutdown shall be initiated and the reactor shall be in HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours.

<u>Notes</u>

(a) 1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

BASES

BACKGROUND - Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During unit life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE limiting condition for operation (LCO) is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

Leakage from the RCS is collected in the containment or by other systems. These systems are the Main Steam System, Condensate and Feedwater System, the Gaseous and Liquid Waste Disposal Systems, the Component Cooling System, and the Chemical and Volume Control System.

Detection of leaks from the RCS is by one or more of the following:

1. An increased amount of makeup water required to maintain normal level in the pressurizer.
2. A high temperature alarm in the leakoff piping provided to collect reactor head flange leakage.
3. Containment sump water level indication.
4. Containment pressure, temperature, and humidity indication.

If there is significant radioactive contamination of the reactor coolant, the radiation monitoring system provides a sensitive indication of primary system leakage. Radiation monitors which indicate primary system leakage include the containment gas and particulate monitors, the condenser air ejector monitor, the component cooling water monitor, and the steam generator blowdown monitor.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES - Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 1 gpm or increases to 1 gpm as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a main steam line break (MSLB) accident. Other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The UFSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The MSLB is less limiting for site radiation releases than the SGTR. The safety analysis for the MSLB accident assumes 1 gpm total primary to secondary LEAKAGE, including 500 gpd leakage into the faulted generator. The dose consequences resulting from the MSLB and the SGTR accidents are within the limits defined in the plant licensing basis.

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION - RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

   No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY - In REACTOR OPERATION conditions where T_{avg} exceeds 200°F, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In COLD SHUTDOWN and REFUELING SHUTDOWN, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.1.C.5 measures leakage through each individual pressure isolation valve (PIV) and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

3.1.C.2.a

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This completion time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

3.1.C.2.b and 3.1.C.3

If any pressure boundary LEAKAGE exists, or primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In COLD SHUTDOWN, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

REFERENCES

1. UFSAR, Chapter 4, Surry Units 1 and 2.
2. UFSAR, Chapter 14, Surry Units 1 and 2.
3. NEI 97-06, "Steam Generator Program Guidelines."
4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

D. RCS Specific Activity

Applicability

The following specifications are applicable whenever T_{avg} (average RCS temperature) exceeds 200°F.

Specification

1. The specific activity of the primary coolant shall be limited to $\leq$ 1 μCi/gm DOSE EQUIVALENT I-131.

   a. With the specific activity of the primary coolant > 1 μCi/gm DOSE EQUIVALENT I-131, verify DOSE EQUIVALENT I-131 $\leq$ 10 μCi/gm once per 4 hours.

   b. With the specific activity of the primary coolant > 1 μCi/gm DOSE EQUIVALENT I-131, but $\leq$ 10 μCi/gm, unit startup or POWER OPERATION may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT I-131 to $\leq$ 1 μCi/gm limit.

   c. With the specific activity of the primary coolant > 1 μCi/gm DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or DOSE EQUIVALENT I-131 is > 10 μCi/gm, place the reactor in HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

2. The specific activity of the primary coolant shall be limited to $\leq$ 234 μCi/gm DOSE EQUIVALENT XE-133.

   a. With the specific activity of the primary coolant > 234 μCi/gm DOSE EQUIVALENT XE-133, unit startup or POWER OPERATION may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT XE-133 to $\leq$ 234 μCi/gm limit.

   b. With the specific activity of the primary coolant > 234 μCi/gm DOSE EQUIVALENT XE-133 for more than 48 hours during one continuous time interval, place the reactor in HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

BASES

BACKGROUND - The maximum dose that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at the low population zone outer boundary for the radiological release duration, is specified in 10 CFR 50.67 (Ref. 1). Doses to control room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents.

The Reactor Coolant System (RCS) specific activity Limiting Condition for Operation (LCO) limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the dose consequences in the event of a steam line break (SLB) or steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2).

APPLICABLE SAFETY ANALYSES - The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite and control room doses meet the appropriate Standard Review Plan acceptance criteria following a SLB or SGTR accident. The safety analyses (Refs. 3 and 4) assume the specific activity of the reactor coolant is at the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.6.H, Secondary Specific Activity.

The analyses for the SLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The safety analyses consider two cases of reactor coolant iodine specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a SLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity is at 10.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 234 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis assumes a coincident loss of offsite power. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) system is placed in service.

The SLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor trip occurs after the generation of an SI signal on low steam line pressure. The affected SG blows down completely and steam is vented directly to the Turbine Building to maximize control room dose. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR system is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible if the activity levels do not exceed 10.0 μCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO - The iodine specific activity in the reactor coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 234 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet the appropriate SRP acceptance criteria (Ref. 2).

The SLB and SGTR accident analyses (Refs. 3 and 4) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a SLB or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 2).

APPLICABILITY - In REACTOR OPERATION conditions where Tavg exceeds 200°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a SLB or SGTR to within the SRP acceptance criteria (Ref. 2).

In COLD SHUTDOWN and REFUELING SHUTDOWN the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary leakage is minimal. Therefore, the monitoring of RCS specific activity is not required.

ACTIONS

3.1.D.1.a

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is $\leq$ 10.0 μCi/gm. The completion time of 4 hours is required to obtain and analyze a sample. Sampling is continued every 4 hours to provide a trend.

3.1.D.1.b

The DOSE EQUIVALENT I-131 must be restored to within limit within 48 hours. The completion time of 48 hours is acceptable since it is expected that, if there were an iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

A unit startup and/or continued plant operation is permitted relying on required actions 3.1.D.1.a and b while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, POWER OPERATION.

3.1.D.1.c

If the required action of Condition 3.1.D.1.a or 3.1.D.1.b is not met, or if the DOSE EQUIVALENT I-131 is > 10.0 μCi/gm, the reactor must be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours. The required completion times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

3.1.D.2.a

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within the limit within 48 hours. The completion time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of a SLB or SGTR occurring during this time period.

A unit startup and/or continued plant operation is permitted relying on required action 3.1.D.2.a while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, POWER OPERATION.

3.1.D.2.b

If the required action or associated Allowed Outage Time of Condition 3.1.D.2.a is not met, or if the DOSE EQUIVALENT XE-133 is > 234 μCi/gm, the reactor must be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours. The required action and completion time are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

REFERENCES

1. 10 CFR 50.67

2. Standard Review Plan (SRP) Section 15.0.1 "Radiological Consequence Analyses Using Alternative Source Terms"

3. UFSAR, Section 14.3.1 Steam Generator Tube Rupture

4. UFSAR, Section 14.3.2 Steam Line Break

E. Minimum Temperature for Criticality

Specifications

1. Except during LOW POWER PHYSICS TESTS, the reactor shall not be made critical at any Reactor Coolant System temperature above which the moderator temperature coefficient is more positive than the limit specified in the CORE OPERATING LIMITS REPORT. The maximum upper limit for the moderator temperature coefficient shall be:

   a. + 6 pcm/°F at less than 50% of RATED POWER, or

   b. + 6 pcm/°F at 50% of RATED POWER and linearly decreasing to 0 pcm/°F at RATED POWER.

2. In no case shall the reactor be made critical with the Reactor Coolant System temperature below the limiting value of RT_{NDT} + 10°F, where the limiting value of RT_{NDT} is as determined in Part B of this specification.

3. When the Reactor Coolant System temperature is below the minimum temperature as specified in E-2 above, the reactor shall be subcritical by an amount equal to or greater than the potential reactivity insertion due to primary coolant depressurization.

4. The reactor shall not be made critical when the Reactor Coolant System temperature is below 538°F.

Basis

During the early part of a fuel cycle, the moderator temperature coefficient may be calculated to be slightly positive at coolant temperatures in the power operating range. The moderator temperature coefficient will be most positive near the beginning of cycle life, generally corresponding to when the boron concentration in the coolant is the greatest. Later in the cycle, the boron concentration in the coolant will generally be lower and the moderator temperature coefficient will be less positive or will be negative in the power operating range. At the beginning of cycle life, during pre-operational physics tests, measurements are made to determine that the moderator temperature coefficient is less than the limit specified in the CORE OPERATING LIMITS REPORT.

The requirement that the reactor is not to be made critical when the moderator coefficient is greater than the low power limit specified in the CORE OPERATING LIMITS REPORT has been imposed to prevent any unexpected power excursion during normal operations as a result of either an increase of moderator temperature or decrease of coolant pressure. This requirement is waived during LOW POWER PHYSICS TESTS to permit measurement of reactor moderator coefficient and other physics design parameters of interest. During physics tests, special operation precautions will be taken. In addition, the strong negative Doppler coefficient(2)(3) and the small integrated Delta k/k would limit the magnitude of a power excursion resulting from a reduction of moderator density.

The requirement that the reactor is not to be made critical with a Reactor Coolant System temperature below the limiting value of RT_{NDT} + 10°F provides increased assurance that the proper relationship between Reactor Coolant System pressure and temperature will be maintained during system heatup and pressurization whenever the reactor vessel is in the nil ductility transition temperature range. Heatup to this temperature is accomplished by operating the reactor coolant pumps.

The requirement that the reactor is not to be made critical with a Reactor Coolant System temperature below 538°F provides added assurance that the assumptions made in the safety analyses remain bounding by maintaining the moderator temperature within the range of those analyses.

If a specified shutdown reactivity margin is maintained (TS Section 3.12), there is no possibility of an accidental criticality as a result of an increase of moderator temperature or a decrease of coolant pressure.

(1) UFSAR Figure 3.3-8
(2) UFSAR Table 3.3-1
(3) UFSAR Figure 3.3-9

4. Concentrations of contaminants in the reactor coolant shall not exceed the following maximum limits when the reactor coolant temperature is below 250 degrees F:

Contaminant	Normal Concentration (PPM)	Transients not to exceed 24 hours (PPM)
a. Chloride	0.15	1.5
b. Fluoride	0.15	1.5

If the limits above are exceeded, the reactor shall be immediately brought to COLD SHUTDOWN and the cause of the out-of-specification condition shall be ascertained and corrected.

5. For the purposes of correcting the contaminant concentrations to meet Technical Specifications 3.1.F.1 and 3.1.F.4 above, increase in coolant temperature consistent with operation of primary coolant pumps for a short period of time to assure mixing of the coolant shall be permitted. This increase in temperature to assure mixing shall in no case cause the coolant temperature to exceed 250 degrees F.

6. For conditions above COLD SHUTDOWN, if more than one contaminant or contaminants transient, which results in contaminant levels exceeding any of the normal steady state operation limits specified in 3.1.F.1 or 3.1.F.4, is experienced in any seven consecutive day period, the reactor shall be placed in COLD SHUTDOWN until the cause of the out-of-specification operation is ascertained and corrected.

Basis

By maintaining the oxygen, chloride and fluoride concentrations in the reactor coolant below the limits as specified in technical specification 3.1.F.1 and 3.1.F.4 the integrity of the reactor coolant system is assured under all operating conditions.(1) If these limits are exceeded, measures can be taken to correct the condition, e.g., replacement of ion exchange resin, or adjustment of the hydrogen concentration in the volume control tank.(2) Because of the time dependent nature of any adverse effects arising from oxygen, chloride, and fluoride concentration in excess of the limits, it is not necessary to shutdown immediately if the condition can be corrected. Thus the period of 24 hours for corrective action to restore concentrations within the limits has been established. If the corrective action has not been effective at the end of the 24 hour period, then the reactor will be brought to COLD SHUTDOWN and the corrective action will continue.

In restoring the contaminant concentrations to within specification limits in the event such limits were exceeded, mixing of the primary coolant with the reactor coolant pumps may be required. This will result in a small heatup of short duration which will not increase the average coolant temperature above 250°F.

More than one contaminant transient, in any seven consecutive day period, that results in exceeding normal steady state operation limits, could be indicative of unforeseen chemistry control problems. Such potential problems warrant investigation, correction and measures to insure that the integrity of the Reactor Coolant System is maintained.

References

(1) UFSAR 4.2
(2) UFSAR 9.2

G. Reactor Coolant System Overpressure Mitigation

Specification

1. The Reactor Coolant System (RCS) overpressure mitigating system shall be OPERABLE as described below:

   a. Whenever the RCS average temperature is greater than 350°F, a bubble shall exist in the pressurizer with the necessary sprays and heaters OPERABLE.

   b. Prior to decreasing RCS average temperature below 350°F, verify a maximum of one charging pump is capable of injecting into the RCS and that each accumulator is isolated. Thereafter, once per 12 hours:

      (1) Verify that a maximum of one charging pump is capable of injecting into the RCS.

      (2) Verify that each accumulator is isolated, if isolation is required.

   c. Whenever the RCS average temperature is less than or equal to 350°F and the reactor vessel head is bolted:

      (1) A maximum of one charging pump shall be OPERABLE and capable of injecting into the RCS. Two charging pumps may be in operation momentarily during transfer of operation from one charging pump to another.

      and

      (2) The accumulators shall be isolated (accumulator discharge valves closed and their respective breakers locked, sealed or otherwise secured in the open position). Isolation is not required if the accumulator pressure is less than the pressurizer PORV setpoint specified in TS 3.1.G.1.c.(4).

      and

(3) During the initial 72 hours, maintain a bubble in the pressurizer with a maximum narrow range level of 33%,

or

(4) Maintain two Power Operated Relief Valves (PORV) OPERABLE with a lift setting of ≤ 390 psig and verify each PORV block valve is open at least once per 72 hours,

or

(5) The RCS shall be vented through one open PORV or an equivalent size opening as specified below:

(a) with the RCS vented through an unlocked open vent path, verify the path is open at least once per 12 hours, or

(b) with the RCS vented through a locked open vent path verify the path is open at least once per 31 days.

2. The requirements of Specification 3.1.G.1.c.(4) may be modified as follows:

a One PORV may be inoperable in INTERMEDIATE SHUTDOWN with the RCS average temperature > 200°F but < 350°F for a period not to exceed 7 days. If the inoperable PORV is not restored to OPERABLE status within 7 days, then completely depressurize the RCS and vent through one open PORV or an equivalent size opening within the next 8 hours.

b One PORV may be inoperable in COLD SHUTDOWN or REFUELING SHUTDOWN with the reactor vessel head bolted for a period not to exceed 24 hours. If the inoperable PORV is not restored to OPERABLE status within 24 hours then completely depressurize the RCS and vent through one open PORV or an equivalent size opening within 8 hours.

c. With both PORV's inoperable, depressurize the RCS within 8 hours unless Specification 3.1.G.1.c.(3) is in effect. When the RCS has been depressurized, vent the RCS through one open PORV or an equivalent sized opening, or establish the conditions listed below. Maintain the RCS depressurized until both PORV's have been restored to OPERABLE status.

(1) A maximum pressurizer narrow range level of 33%.
(2) The series RHR inlet valves open and their respective breakers locked open or an alternate letdown path OPERABLE.
(3) A maximum of one charging pump is capable of injecting into the RCS.
(4) Safety Injection accumulator discharge valves closed and their respective breakers locked, sealed, or otherwise secured in the open position.

d. When the conditions noted in 3.1.G.2.c.(1) through 3.1.G.2.c.(4) above are required to be established, verify the required conditions are met at least once per 12 hours.

3. In the event that the Reactor Coolant System Overpressure Mitigating System is used to mitigate a RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.6 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the mitigating system or the administrative controls on the transient and any corrective actions necessary to prevent recurrence.

Basis

The operability of two PORV's or the RCS vented through an opened PORV ensures that the Reactor Vessel will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when the Reactor Coolant System average temperature is $\leq$ 350°F and the Reactor Vessel Head is bolted. When the Reactor Coolant System average temperature is > 350°F, overpressure protection is provided by a bubble in the pressurizer and/or pressurizer safety valves. A single PORV has adequate relieving capability to protect the Reactor Vessel from overpressurization when the transient is limited to either (1) the start of an idle Reactor Coolant Pump with the secondary water temperature of a steam generator ≤ 50°F above the RCS cold leg temperature or (2) the start of a charging pump and its injection into a water solid RCS.

The limitation for a maximum of one charging pump allowed OPERABLE and the surveillance required to verify that two charging pumps are inoperable below 350°F provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV, or equivalent. The Safety Injection accumulators are not considered a credible mass input mechanism for RCS low temperature overpressurization concerns. There are administrative controls to ensure isolation, including de-energizing the Safety Injection (SI) accumulator isolation valves, during plant shutdown conditions (RCS pressure less than 1000 psig) to prevent inadvertent SI accumulator discharge into the RCS for low temperature overpressurization concerns. An undesired pressurizer PORV lift due to inadvertent SI accumulator discharge is not possible when SI accumulator pressure is less than the low temperature PORV lift setpoint specified in TS 3.1.G. Therefore, SI accumulator isolation, and verification of such isolation is not necessary when SI accumulator pressure is less than the low temperature PORV setpoint.

A maximum pressurizer narrow range level of 33% has been selected to provide sufficient time, approximately 10 minutes, for operator response in case of a malfunction resulting in maximum charging flow from one charging pump (530 gpm). Operator action would be initiated by at least two alarms that would occur between the normal operating level and the maximum allowable level (33%). When both PORVs are inoperable and it is impossible to manually open at least one PORV, additional administrative controls shall be implemented to prevent a pressure transient that would exceed the limits of Appendix G to 10 CFR Part 50.

The requirements of this specification are only applicable when the Reactor Vessel head is bolted. When the Reactor Vessel head is unbolted, a RCS pressure of < 100 psig will lift the head, thereby creating a relieving capability equivalent to at least one PORV.

H. Steam Generator (SG) Tube Integrity

Applicability

The following specifications are applicable whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Specifications

1. SG tube integrity shall be maintained, and all SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the Steam Generator Program.

2. If the requirements of 3.1.H.1 are not met for one or more SG tubes, then perform the following:[1]

   a. Within 7 days, verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection; and

   b. Plug the affected tube(s) in accordance with the Steam Generator Program prior to T_{avg} exceeding 200°F following the next refueling outage or SG tube inspection.

3. If the required actions of Specification 3.1.H.2 are not completed within the specified completion time, or SG tube integrity is not maintained, the unit shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

Note:

1. A separate TS action entry is allowed for each SG tube.

BASES

BACKGROUND - Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.1.A.2.

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 6.4.Q, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 6.4.Q, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 6.4.Q. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES - The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of an SGTR event assumes a bounding primary to secondary LEAKAGE rate of 1 gpm, which is conservative with respect to the operational LEAKAGE rate limits in Specification 3.1.C, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The UFSAR analysis for SGTR assumes the contaminated secondary fluid is released via power operated relief valves or safety valves. The source term in the primary system coolant is transported to the affected (ruptured) steam generator by the break flow. The affected steam generator discharges steam to the environment for 30 minutes until the generator is manually isolated. The 1 gpm primary to secondary LEAKAGE transports the source term to the unaffected steam generators. Releases continue through the unaffected steam generators until the Residual Heat Removal System is placed in service.

The analyses for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be within Specification 3.1.D, "Maximum Reactor Coolant Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 50.67 (Ref. 3) or Regulatory Guide 1.183 (Ref. 4), as appropriate.

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION - The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.4.Q, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that significantly affect burst or collapse. In that context, the term "significantly" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 5) and Draft Regulatory Guide 1.121 (Ref. 6).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in Specification 3.1.C, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY - Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced when T_{avg} exceeds 200°F.

RCS conditions are far less challenging in COLD SHUTDOWN and REFUELING SHUTDOWN than during INTERMEDIATE SHUTDOWN, HOT SHUTDOWN, REACTOR CRITICAL and POWER OPERATION. In COLD SHUTDOWN and REFUELING SHUTDOWN, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS - The actions are modified by a Note clarifying that the conditions may be entered independently for each SG tube. This is acceptable because the required actions provide appropriate compensatory actions for each affected SG tube. Complying with the required actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent condition entry and application of associated required actions.

3.1.H.2.a and b

Specification 3.1.H.2 applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 4.19. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Specification 3.1.H.3 applies.

A completion time of 7 days is sufficient to complete the evaluation while minimizing the risk of unit operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, required action 3.1.H.2.b allows unit operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to T_{avg} exceeding 200°F following the next refueling outage or SG inspection. This completion time is acceptable since operation until the next inspection is supported by the operational assessment.

3.1.H.3

If the required actions and associated completion times of Specification 3.1.H.2 are not met or if SG tube integrity is not being maintained, the reactor must be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours.

The allowed completion times are reasonable, based on operating experience, to reach the desired unit conditions from full power conditions in an orderly manner and without challenging plant systems.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 50.67.
4. Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.
5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
6. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
7. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

Surry Units 1 and 2
Reactor Coolant System Heatup Limitations

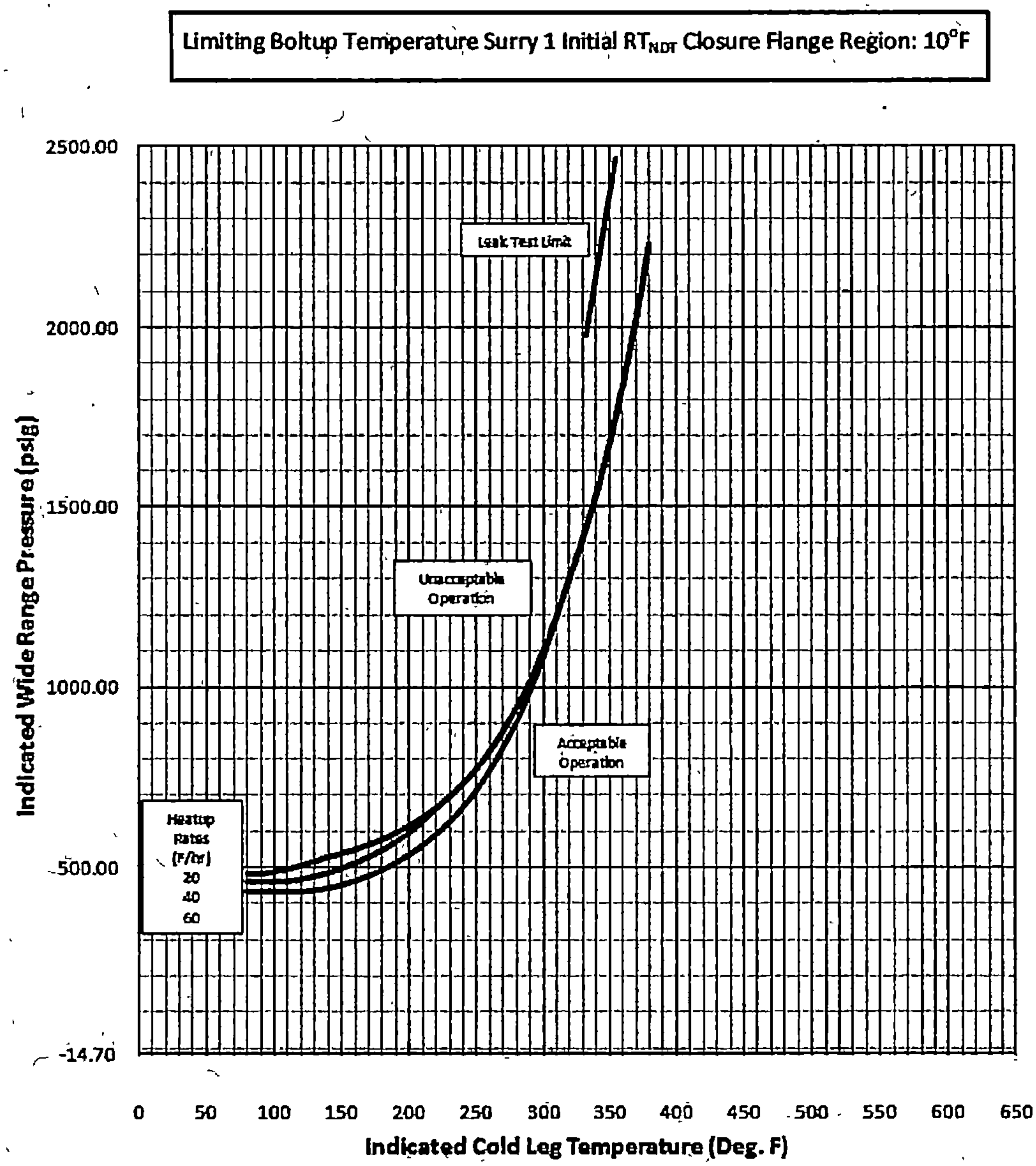

Figure 3.1-1 : Surry Units 1 and 2 Reactor Coolant System Heatup Limitations (Heatup Rates up to 60°F/hr) Applicable for 68 EFPY

Surry Units 1 and 2
Reactor Coolant System Cooldown Limitations

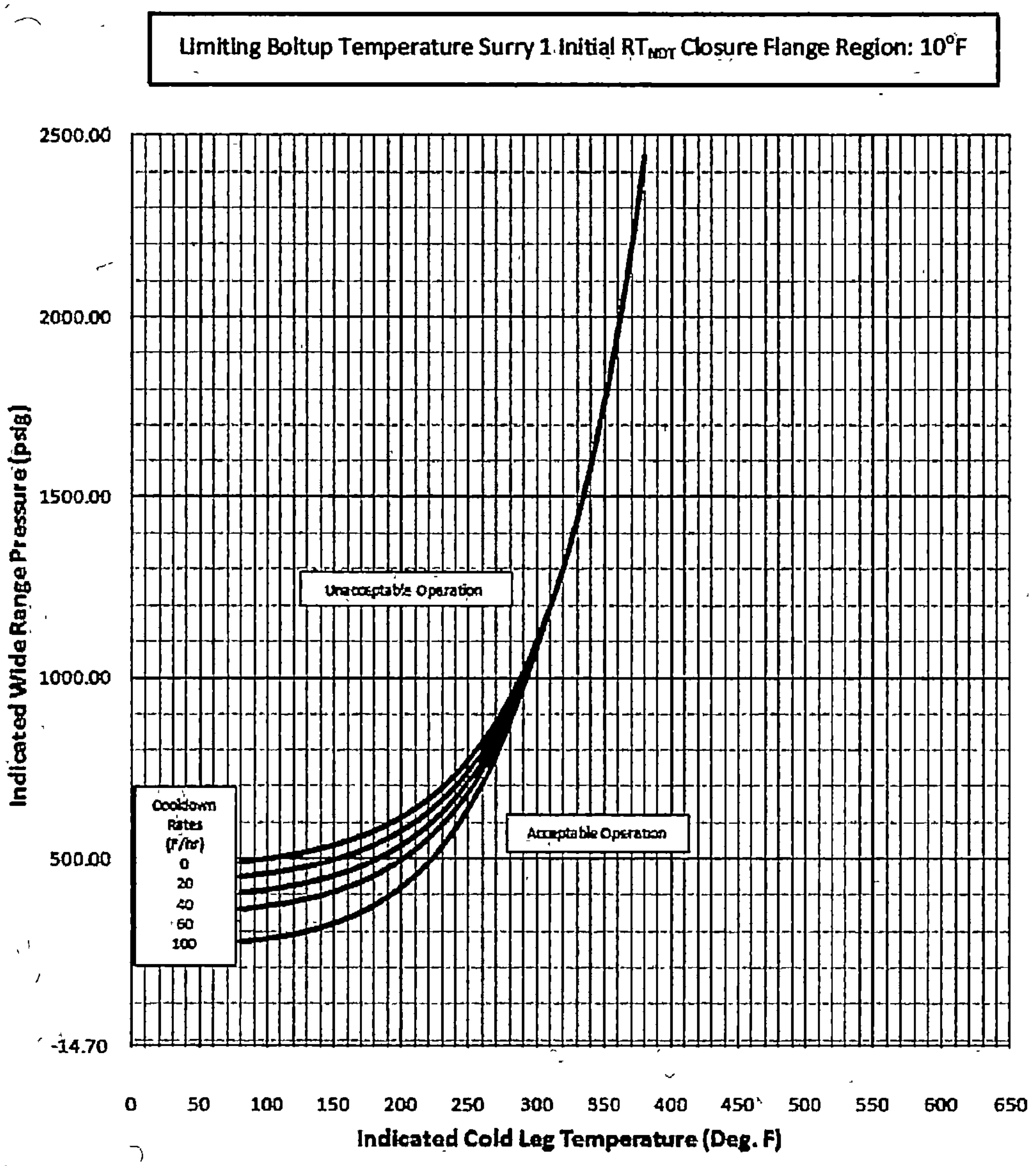

Figure 3.1-2 : Surry Units 1 and 2 Reactor Coolant System Cooldown Limitations (Cooldown Rates up to 100°F/hr) Applicable for 68 EFPY

3.2. CHEMICAL AND VOLUME CONTROL SYSTEM

Applicability

Applies to the operational status of the Chemical and Volume Control System.

Objective

To define those conditions of the Chemical and Volume Control System necessary to ensure safe reactor operation.

Specification

A. When fuel is in a reactor, there shall be at least one flow path to the core for boric acid injection. The minimum capability for boric acid injection shall be equivalent to that supplied from the refueling water storage tank.

B. The reactor shall not be critical unless:

1. At least two boron injection subsystems are OPERABLE consisting of:
    a. A Chemical and Volume Control subsystem consisting of:
        1. One OPERABLE flow path,
        2. One OPERABLE charging pump,
        3. One OPERABLE boric acid transfer pump,
        4. The common OPERABLE boric acid storage system with:
            a. A minimum contained borated water volume of 6000 gallons per unit,
            b. A boron concentration of at least 7.0 weight percent but not more than 8.5 weight percent boric acid solution, and
            c. A minimum solution temperature of 112°F.
            d. An OPERABLE boric acid transfer pump for recirculation.

b. A subsystem supplying borated water from the refueling water storage tank via a charging pump to the Reactor Coolant System consisting of:

1. One OPERABLE flow path,
2. One OPERABLE charging pump,
3. The OPERABLE refueling water storage tank with:
   a. A minimum contained borated water volume of 387,100 gallons,
   b. A boron concentration of at least 2300 ppm but not more than 2500 ppm, and
   c. A maximum solution temperature of 45°F.

2. One charging pump from the opposite unit is available with:

   a. the pump being OPERABLE except for automatic initiation instrumentation,
   b. offsite or emergency power may be inoperable when in COLD SHUTDOWN, and
   c. the pump capable of being used for alternate shutdown with the opening of the charging pump cross-connect valves.

C. The requirements of Specification 3.2.B may be modified as follows:

1. With only one of the boron injection subsystems OPERABLE, restore at least two boron injection subsystems to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 6 hours.
2. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or place the reactor in HOT SHUTDOWN within the next 6 hours.

   a. For conditions where the RWST is inoperable due to boron concentration or solution temperature not being within the limits of Specification 3.3.A.1, restore the parameters to within specified limits in 8 hours or place the reactor in HOT SHUTDOWN within the next 6 hours.

3. With no charging pump from the opposite unit available, return at least one of the opposite unit's charging pumps to available status in accordance with Specification 3.2.B.2 within 7 days or place the reactor in HOT SHUTDOWN within the next 6 hours.

D. If the requirements of Specification 3.2.B are not satisfied as allowed by Specification 3.2.C, the reactor shall be placed in COLD SHUTDOWN within the following 30 hours.

E. During REFUELING SHUTDOWN, COLD SHUTDOWN, INTERMEDIATE SHUTDOWN, and HOT SHUTDOWN, the following valves in the affected unit shall be locked, sealed, or otherwise secured in the closed position except during planned dilution or makeup activities:

1. Unit 1:
   a. Valve 1-CH-223, or
   b. Valves 1-CH-212, 1-CH-215, and 1-CH-218.
2. Unit 2:
   a. Valve 2-CH-223, or
   b. Valves 2-CH-212, 2-CH-215, and 2-CH-218.
3. Following planned dilution or makeup activities, the valves listed in Specifications 3.2.E.1 and 3.2.E.2 above, for the affected unit, shall be locked, sealed, or otherwise secured in the closed position within 15 minutes.

F. The requirements of Specification 3.2.E may be modified as follows:

1. During the approach to critical in HOT SHUTDOWN, closure of the valves in Specification 3.2.E.1 and 3.2.E.2, for the affected unit, is not required.
2. Upon entering HOT SHUTDOWN following reactor shutdown from POWER OPERATION or REACTOR CRITICAL, the valves listed in Specifications 3.2.E.1 and 3.2.E.2 above, for the affected unit, shall be locked, sealed, or otherwise secured in the closed position within 1 hour. If a planned dilution or makeup activity is in progress upon entry into HOT SHUTDOWN, the valves listed shall be locked, sealed, or otherwise secured in the closed position within 15 minutes following completion of the activity or within 1 hour of entry into HOT SHUTDOWN whichever is latest.

Basis

The Chemical and Volume Control System provides control of the Reactor Coolant System boron inventory. This is normally accomplished by using boric acid transfer pumps which discharge to the suction of each unit's charging pumps. The Chemical and Volume Control System contains four boric acid transfer pumps. Two of these pumps are normally assigned to each unit but, valving and piping arrangements allow pumps to be shared such that three out of four pumps can service either unit. An alternate (not normally used) method of boration is to use the charging pumps taking suction directly from the refueling water storage tank. There are two sources of borated water available to the suction of the charging pumps through two different paths; one from the refueling water storage tank and one from the discharge of the boric acid transfer pumps.

A. The boric acid transfer pumps can deliver the boric acid tank contents (7.0% solution of boric acid) to the charging pumps.

B. The charging pumps can take suction from the volume control tank, the boric acid transfer pumps and the refueling water storage tank. Reference is made to Technical Specification 3.3.

The quantity of boric acid in storage from either the boric acid tanks or the refueling water storage tank is sufficient to borate the reactor coolant in order to reach COLD SHUTDOWN at any time during core life.

Approximately 6000 gallons of the 7.0% solution of boric acid are required to meet COLD SHUTDOWN conditions. Thus, a minimum of 6000 gallons in the boric acid tank is specified. An upper concentration limit of 8.5% boric acid in the tank is specified to maintain solution solubility at the specified low temperature limit of 112 degrees F.

The Boric Acid Tank(s) are supplied with level alarms which would annunciate if a leak in the system occurred.

For one-unit operation, it is required to maintain available one charging pump with a source of borated water on the opposite unit, the associated piping and valving, and the associated instrumentation and controls in order to maintain the capability to cross-connect the two unit's charging pump discharge headers. In the event the operating unit's charging pumps become inoperable, this permits the opposite unit's charging pump to be used to bring the disabled unit to COLD SHUTDOWN conditions. Initially, the need for the charging pump cross-connect was identified during fire protection reviews.

The requirement that certain valves remain closed during REFUELING SHUTDOWN, COLD SHUTDOWN, INTERMEDIATE SHUTDOWN, and HOT SHUTDOWN conditions, except for planned boron dilution or makeup activities, provides assurance that a high flow rate inadvertent boron dilution will not occur. The lockout requirement is relaxed in HOT SHUTDOWN (TS 3.2.F) during the approach to critical and within 1 hour after reactor shutdown. This allows startup and shutdown activities to proceed without undue operator burden. This specification is not applicable in REACTOR CRITICAL or POWER OPERATION.

For purposes of Specification 3.2.F, 'approach to critical' is defined to be the operator controlled adjustment of RCS boron concentration or rod position with the intention of bringing the reactor critical.

References

(1) UFSAR Section 9.1, Chemical and Volume Control System

(2) UFSAR Section 14.2.5, Chemical and Volume Control System Malfunction

3.3 SAFETY INJECTION SYSTEM

Applicability

Applies to the operating status of the Safety Injection System.

Objective

To define those limiting conditions for operation that are necessary to provide sufficient borated water to remove decay heat from the core in emergency situations.

Specifications

A. A reactor shall not be made critical unless:

1. The refueling water storage tank (RWST) is OPERABLE with:

   a. A contained borated water volume of at least 387,100 gallons.
   b. A boron concentration of at least 2300 ppm but not greater than 2500 ppm.
   c. A maximum solution temperature of 45° F.

2. Each safety injection accumulator is OPERABLE with:

   a. A borated water volume of at least 975 cubic feet but not greater than 1025 cubic feet.
   b. A boron concentration of at least 2250 ppm.
   c. A nitrogen cover-pressure of at least 600 psia.
   d. The safety injection accumulator discharge motor operated valve blocked open by de-energizing AC power and the valves's breaker locked, sealed or otherwise secured in the open position when the reactor coolant system pressure is greater than 1000 psig.

3. Two safety injection subsystems are OPERABLE with subsystems comprised of:

   a. One OPERABLE high head charging pump.
   b. One OPERABLE low head safety injection pump.
   c. An OPERABLE flow path capable of transferring fluid to the Reactor Coolant System when taking suction from the refueling water storage tank on a safety injection signal or from the containment sump when suction is transferred during the recirculation phase of operation.

B. The requirements of Specification 3.3.A may be modified as follows:

1. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or place the reactor in HOT SHUTDOWN within the next 6 hours.

   a. For conditions where the RWST is inoperable due to boron concentration or solution temperature not being within the limits of Specification 3.3.A.1, restore the parameters to within specified limits in 8 hours or place the reactor in HOT SHUTDOWN within the next 6 hours.

2. With one safety injection accumulator inoperable, restore the accumulator to OPERABLE status within 4 hours or place the reactor in HOT SHUTDOWN within the next 6 hours.

   a. For conditions where one safety injection accumulator is inoperable due to boron concentration not being within the limits of Specification 3.3.A.2, restore the accumulator to within specified limits in 72 hours or place the reactor in HOT SHUTDOWN within the next 6 hours.
   b. Power may be restored to any valve or breaker referenced in Specification 3.3.A.2.d for the purpose of testing or

maintenance provided that not more than one valve has power restored, and the testing and maintenance is completed and power removed within 4 hours.

3. With one safety injection subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or place the reactor in HOT SHUTDOWN within the next 6 hours.

C. If the requirements of Specification 3.3.A are not satisfied as allowed by Specification 3.3.B, the reactor shall be placed in COLD SHUTDOWN in the following 30 hours.

Basis

The normal procedure for starting the reactor is, first, to heat the reactor coolant to near operating temperature by running the reactor coolant pumps. The reactor is then made critical by withdrawing control rods and/or diluting boron in the coolant. With this mode of startup the Safety Injection System is required to be OPERABLE as specified. During LOW POWER PHYSICS TESTS there is a negligible amount of energy stored in the system. Therefore, an accident comparable in severity to the Design Basis Accident is not possible, and the full capacity of the Safety Injection System would not be necessary.

Management of gas voids is important to Safety Injection System operability. The OPERABLE status of the subsystems is to be demonstrated by periodic tests, detailed in TS Section 4.11. A large fraction of these tests are performed while the reactor is operating in the power range. If a subsystem is found to be inoperable, it will be possible in most cases to effect repairs and restore the subsystem to full operability within a relatively short time. A subsystem being inoperable does not negate the ability of the system to perform its function, but it reduces the redundancy provided in the reactor design and thereby limits the ability to tolerate additional subsystem failures. In some cases, additional components (i.e., charging pumps) are installed to allow a component to be inoperable without affecting system redundancy.

If the inoperable subsystem is not repaired within the specified allowable time period, the reactor will initially be placed in HOT SHUTDOWN to provide for reduction of the decay heat from the fuel, and consequent reduction of cooling requirements after a postulated loss-of-coolant accident. If the malfunction(s) is not corrected the reactor will be placed in COLD SHUTDOWN following normal shutdown and cooldown procedures.

Assuming the reactor has been operating at full RATED POWER for at least 100 days, the magnitude of the decay heat production decreases as follows after a unit trip from full RATED POWER.

Time After Shutdown	Decay Heat. (% of RATED POWER)
1 min.	3.7
30 min.	1.6
1 hour	1.3
8 hours	0.75
48 hours	0.48

Thus, the requirement for core cooling in case of a postulated loss-of-coolant accident, while in HOT SHUTDOWN, is reduced by orders of magnitude below the requirements for handling a postulated loss-of-coolant accident occurring during POWER OPERATION. Placing and maintaining the reactor in HOT SHUTDOWN significantly reduces the potential consequences of a loss-of-coolant accident, allows access to some of the Safety Injection System components in order to effect repairs, and minimizes the plant's exposure to thermal cycling.

Failure to complete repairs within 72 hours is considered indicative of unforeseen problems (i.e., possibly the need of major maintenance). In such a case, the reactor is placed in COLD SHUTDOWN.

The accumulators are able to accept leakage from the Reactor Coolant System without any effect on their operability. Allowable inleakage is based on the volume of water that can be added to the initial amount without exceeding the volume given in Specification 3.3.A.2.

The accumulators (one for each loop) discharge into the cold leg of the reactor coolant piping when Reactor Coolant System pressure decreases below accumulator pressure, thus assuring rapid core cooling for large breaks. The line from each accumulator is provided with a motor-operated valve to isolate the accumulator during reactor start-up and shutdown to preclude the discharge of the contents of the accumulator when not required.

Accumulator Motor Operated Discharge Isolation Valves

Unit No. 1	Unit No. 2
MOV 1865A	MOV 2865A
MOV 1865B	MOV 2865B
MOV 1865C	MOV 2865C

However, to assure that the accumulator valves satisfy the single failure criteria, they will be locked, sealed or otherwise secured open by de-energizing the valve motor operators when the reactor coolant pressure exceeds 1000 psig. The operating pressure of the Reactor Coolant System is 2235 psig and accumulator injection is initiated when this pressure drops to 600 psia. De-energizing the motor operator when the pressure exceeds 1000 psig allows sufficient time during normal startup operation to perform the actions required to de-energize the valve. This procedure will assure that there is an OPERABLE flow path from each accumulator to the Reactor Coolant System during POWER OPERATION and that safety injection can be accomplished.

The removal of power from the valves listed above will assure that the systems of which they are a part satisfy the single failure criterion.

3.4 SPRAY SYSTEMS

Applicability

Applies to the operational status of the Spray Systems.

Objective

To define those limiting conditions for operation of the Spray Systems necessary to assure safe unit operation.

Specification

A. A unit's Reactor Coolant System temperature or pressure shall not be made to exceed 350°F or 450 psig, respectively, unless the following Spray System conditions in the unit are met:

1. Two Containment Spray Subsystems, including containment spray pumps, piping, and valves shall be OPERABLE.

2. Four Recirculation Spray Subsystems, including recirculation spray pumps, coolers, piping, and valves shall be OPERABLE.

3. The refueling water storage tank shall contain at least 387,100 gallons of borated water at a maximum temperature of 45°F. The boron concentration shall be at least 2300 ppm but not greater than 2500 ppm.

4. The sodium tetraborate decahydrate (NaTB) baskets shall be unobstructed, in place, intact, and shall contain at least 10,760 lbm of sodium tetraborate decahydrate collectively. The NaTB in the baskets shall provide adequate pH adjustment of borated water.

5. All valves, piping, and interlocks associated with the above components which are required to operate under accident conditions shall be OPERABLE.

B. During POWER OPERATION the requirements of Specification 3.4.A may be modified to allow a subsystem or the following components to be inoperable. If the components are not restored to meet the requirements of Specification 3.4.A within the time period specified below, the reactor shall be placed in HOT SHUTDOWN within the next 6 hours. If the requirements of Specification 3.4.A are not satisfied within an additional 48 hours the reactor shall be placed in COLD SHUTDOWN within the following 30 hours.

1. One Containment Spray Subsystem may be inoperable, provided immediate attention is directed to making repairs and the subsystem can be restored to OPERABLE status within 24 hours.

2. One outside Recirculation Spray Subsystem may be inoperable, provided immediate attention is directed to making repairs and the subsystem can be restored to OPERABLE status within 24 hours.

3. One inside Recirculation Spray Subsystem may be inoperable, provided immediate attention is directed to making repairs and the subsystem can be restored to OPERABLE status within 72 hours.

4. Refueling Water Storage Tank volume may be outside the limits of Specification 3.4.A.3 provided it is restored to within limits within one hour.

   a. For conditions where the RWST is inoperable due to boron concentration or solution temperature not being within the limits specified, restore the parameters to within specified limits in 8 hours.

Basis

The spray systems in each reactor unit consist of two separate parallel Containment Spray Subsystems, each of 100 percent capacity, and four separate parallel Recirculation Spray Subsystems, each of 50 percent capacity.

Each Containment Spray Subsystem draws water independently from the refueling water storage tank (RWST). The water in the tank is cooled to 45°F or below by circulating the water through one of the two RWST coolers with one of the two recirculating pumps. The water temperature is maintained by two mechanical refrigerating units as required. In each Containment Spray Subsystem, the water flows from the tank through an electric motor driven containment spray pump and is sprayed into the containment atmosphere through two separate sets of spray nozzles. The capacity of the spray systems to depressurize the containment in the event of a Design Basis Accident is a function of the pressure and temperature of the containment atmosphere, the service water temperature, and the temperature in the refueling water storage tank as discussed in the Basis of Specification 3.8.

Each Recirculation Spray Subsystem draws water from the common containment sump. In each subsystem the water flows through a recirculation spray pump and recirculation spray cooler, and is sprayed into the containment atmosphere through a separate set of spray nozzles. Two of the recirculation spray pumps are located inside the containment and two outside the containment in the containment auxiliary structure.

With one Containment Spray Subsystem and two Recirculation Spray Subsystems operating together, the spray systems are capable of cooling and depressurizing the containment to 1.0 psig in less than 60 minutes and to subatmospheric pressure within 4 hours following the Design Basis Accident. The Recirculation Spray Subsystems are capable of maintaining subatmospheric pressure in the containment indefinitely following the Design Basis Accident when used in conjunction with the Containment Vacuum System to remove any long term air inleakage. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 1.0 psig (from 1 hour to 4 hours) and is maintained less than 0.0 psig (after 4 hours).

In addition to supplying water to the Containment Spray System, the refueling water storage tank is also a source of water for safety injection following an accident. This water is borated to a concentration which assures reactor shutdown by approximately 5 percent $\Delta k/k$ when all control rods assemblies are inserted and when the reactor is cooled down for refueling.

Management of gas voids is important to the operability of the Spray Systems. Based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations, as supplemented by system walk downs, the Containment Spray Subsystem, Inside Recirculation Spray Subsystem, and Outside Recirculation Spray Subsystem are not susceptible to gas intrusion. Once the piping in the Spray Systems is procedurally filled and placed in service for normal operation, no external sources of gas accumulation or intrusion have been identified for these systems that would affect spray system operation or performance. Thus, the piping in the Spray Systems will remain sufficiently full during normal operation, and periodic monitoring for gas accumulation or intrusion is not required.

References

(1)	UFSAR Section 4	Reactor Coolant System
(2)	UFSAR Section 5.4	Containment Design Evaluation
(3)	UFSAR Section 6.3.1	Spray System
(4)	UFSAR Section 14.5	Loss of Coolant Accident

3.5 RESIDUAL HEAT REMOVAL SYSTEM

Applicability

Applies to the operational status of the Residual Heat Removal System.

Objective

To define the limiting conditions for operation that are necessary to remove decay heat from the Reactor Coolant System in normal shutdown situations.

Specification

A. The following components shall be OPERABLE, as specified in Specifications 3.1.A.1.d, 3.10.A.4, 3.10.A.5, and 3.13.C, as applicable:

   1. Residual heat removal pumps.
   2. Residual heat exchangers.
   3. System piping and valves required to establish a flow path to and from the above components.
   4. Component Cooling System piping and valves required to establish a flow path to and from the above components.

B. The requirements of Specification A may be modified as specified in Specification 3.1.A.1.d, 3.10.C, or 3.13.D, as applicable, and immediate action shall be taken to restore operability/operation of the out of service equipment.

Basis

The Residual Heat Removal System is required to bring the Reactor Coolant System from conditions of approximately 350°F and pressures between 400 and 450 psig to cold shutdown conditions. Heat removal at greater temperatures is by the Steam and Power Conversion System. The Residual Heat Removal System is provided with two pumps and two heat exchangers. If one of the two pumps and/or one of the two heat exchangers is not operative, safe operation of the unit is not affected; however, the time for cooldown to cold shutdown conditions is extended.

The NRC requires that the series motorized valves in the line connecting the RHRS and RCS be provided with pressure interlocks to prevent them from opening when the reactor coolant system is at pressure.

Management of gas voids is important to RHR System operability. Based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations, as supplemented by system walk downs, the RHR System is not susceptible to gas intrusion, except primarily from Safety Injection Accumulator line back leakage through the RHR discharge motor operated valves. If this condition were to occur, it would be identified and mitigated prior to placing the system in service. Once placed in service, RHR System velocities during normal cooldown are sufficient to sweep any gas voids that may have remained in local high points. Controlling RHR System operating flow rates, with the consideration to limiting inlet conditions and RCS level, prevents vortexing and air ingestion into the operating RHR pump and piping. Thus, the piping in the RHR System will remain sufficiently full of water during standby and normal system operation, and periodic monitoring for gas accumulation or intrusion is not required.

References

FSAR Section 9.3 - Residual Heat Removal System

3.6 TURBINE CYCLE

Applicability

Applies to the operating status of the Main Steam and Auxiliary Feed Systems.

Objectives

To define the conditions required in the Main Steam System and Auxiliary Feed System for protection of the steam generator and to assure the capability to remove residual heat from the core during a loss of station power/or accident situations.

Specification

A. A unit's Reactor Coolant System temperature or pressure shall not exceed 350°F or 450 psig, respectively, or the reactor shall not be critical unless the five main steam line code safety valves associated with each steam generator in unisolated reactor coolant loops are OPERABLE with lift settings as specified in Table 3.6-1A and 3.6-1B. Associated system piping shall also be OPERABLE.

B. With Reactor Coolant System conditions less than 350°F and 450 psig and the steam generators being used for heat removal, one motor driven auxiliary feedwater pump and associated flowpath shall be OPERABLE.

C. To assure residual heat removal capabilities, the following conditions shall be met prior to exceeding Reactor Coolant System conditions of 350°F and 450 psig which would preclude operation of the Residual Heat Removal System. The following shall apply:

1. Three auxiliary feedwater pumps shall be OPERABLE.

2. A minimum of 96,000 gallons of water shall be available in the protected condensate storage tank to supply emergency water to the auxiliary feedwater pump suctions.

3. Two redundant flowpaths, including system piping, headers, valves, and control board indication required for operation of the components enumerated in Specifications 3.6.C.1 and 3.6.C.2, shall be OPERABLE.

4. The auxiliary feedwater cross-connect capability shall be available, as follows:

   a. Two of the three auxiliary feedwater pumps and the associated redundant flowpaths on the opposite unit (automatic initiation instrumentation need not be OPERABLE) capable of being used with the opening of the cross-connect.

   b. A minimum of 60,000 gallons of water available in the protected condensate storage tank of the opposite unit to supply emergency water to the auxiliary feedwater pump suction of that unit.

   c. Emergency power supplied to the opposite unit's auxiliary feedwater pumps and to the AFW cross-connect valves, as follows:

      1. Two diesel generators (the opposite unit's diesel generator and the shared backup diesel generator) OPERABLE with each generator's day tank having at least 290 gallons of fuel and with a minimum on-site supply of 35,000 gallons of fuel available.

      2. Two 4160V emergency buses energized.

      3. Two OPERABLE flow paths for providing fuel to the opposite unit's diesel generator and the shared backup diesel generator.

      4. Two station batteries, two chargers and the DC distribution systems OPERABLE.

      5. Emergency diesel generator battery, charger and the DC control circuitry OPERABLE for the opposite unit's diesel generator and for the shared back-up diesel generator.

6. The 480V emergency buses energized which supply power to the auxiliary feedwater cross-connect valves:

   a. For AFW from Unit 1 to Unit 2: Buses 1H1 and 1J1.

   b. For AFW from Unit 2 to Unit 1: Buses 2H1 and 2J1.

7. One of the two physically independent circuits from the offsite transmission network energizing the opposite unit's emergency buses.

D. With Reactor Coolant System conditions less than 350°F and 450 psig and the steam generators being used for heat removal, if either the motor driven pump or the associated flowpath becomes inoperable, immediately initiate action to restore the inoperable equipment to OPERABLE status.

E. With the turbine driven pump inoperable on the affected unit and with Reactor Coolant System temperature and pressure greater than 350°F and 450 psig, respectively, immediately following REFUELING SHUTDOWN and prior to REACTOR CRITICAL, restore the inoperable pump to OPERABLE status within 7 days or be less than 350°F and 450 psig within the next 12 hours.

F. The following actions shall be taken when one or more auxiliary feedwater pumps are inoperable on the affected unit for reasons other than those addressed in Specification 3.6.E:

1. With one auxiliary feedwater pump inoperable, restore the inoperable pump to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

2. With two auxiliary feedwater pumps inoperable, be in HOT SHUTDOWN within 6 hours and be less than 350°F and 450 psig within the next 12 hours.

3. With three auxiliary feedwater pumps inoperable, immediately initiate action to restore one inoperable pump to OPERABLE status. Specification 3.0.1 and all other required actions directing mode changes are suspended until one inoperable pump is restored to OPERABLE status.

G. The following actions shall be taken with inoperability of a component or instrumentation other than the flow instrumentation in one or both redundant auxiliary feedwater flowpaths required by Specification 3.6.C.3 on the affected unit: (See Specification 3.7 and TS Table 3.7-6 for auxiliary feedwater flow instrumentation requirements.)

1. With component or instrumentation inoperability in one redundant flowpath, restore the inoperable component or instrumentation to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

2. With component or instrumentation inoperability affecting both redundant flowpaths, immediately initiate action to restore the inoperable component or instrumentation in one flowpath to OPERABLE status. Specification 3.0.1 and all other required actions directing mode changes are suspended until the inoperable component or instrumentation in one flowpath is restored to OPERABLE status.

H. The specific activity of the secondary coolant system shall be $\leq$ 0.10 μCi/gm DOSE EQUIVALENT I-131. If the specific activity of the secondary coolant system exceeds 0.10 μCi/gm DOSE EQUIVALENT I-131, the reactor shall be placed in HOT SHUTDOWN within 6 hours after detection and in COLD SHUTDOWN within the following 30 hours.

I. The requirements of Specification 3.6.C.4 above concerning the opposite unit's auxiliary feedwater pumps; the associated redundant flowpaths, including piping, headers, valves, and control board indication; the cross-connect piping from the opposite unit; and the protected condensate storage tank may be modified to allow the following components to be inoperable, provided immediate attention is directed to making repairs. Automatic initiation instrumentation associated with the opposite unit's auxiliary feedwater pumps need not be OPERABLE.

1. One of the opposite unit's flowpaths or two of the opposite unit's auxiliary feedwater pumps may be inoperable for a period not to exceed 14 days.

2. Both of the opposite unit's flowpaths; the opposite unit's protected condensate storage tank; the cross-connect piping from the opposite unit; or three of the opposite unit's auxiliary feedwater pumps may be inoperable for a period not to exceed 72 hours. For the specific purpose of performing maintenance related to the operability of all three of the opposite unit's auxiliary feedwater pumps, these components may be inoperable for a period not to exceed 10 days.*

3. A train of the opposite unit's emergency power system as required by Section 3.6.C.4.c above may be inoperable for a period not to exceed 14 days; if this train's inoperability is related to a diesel fuel oil path, one diesel fuel oil path may be "inoperable" for 24 hours provided the other flowpath is proven OPERABLE; if after 24 hours, the inoperable flowpath cannot be restored to service, the diesel shall be considered "inoperable." During this 14 day period, the following limitations apply:

   a. If the offsite power source becomes unable to energize the opposite unit's OPERABLE train, operation may continue provided its associated emergency diesel generator is energizing the OPERABLE train.

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* The compensatory measures identified in the letter from Virginia Electric and Power Company to the US NRC dated June 20, 2022 (ADAMS Accession No. ML22172A134) and listed in the TS 3.6 Basis are required to be in place whenever the 10-day Allowed Outage Time is entered.

b. If the opposite unit's OPERABLE train's emergency diesel generator becomes unavailable, operation may continue for 72 hours provided the offsite power source is energizing the opposite unit's OPERABLE train.

c. Return of the originally inoperable train to OPERABLE status allows the second inoperable train to revert to the 14 day limitation.

If the above requirements are not met, be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

J. The requirements of Specification 3.6.C.2 above may be modified to allow utilization of protected condensate storage tank water with the auxiliary feedwater pumps provided the water level is maintained above 60,000 gallons, sufficient replenishment water is available in the 300,000 gallon condensate storage tank, and replenishment of the protected condensate storage tank is commenced within two hours after the cessation of protected condensate storage tank water consumption.

Basis

A reactor which has been shutdown from power requires removal of core residual heat. While reactor coolant temperature or pressure is > 350°F or 450 psig, respectively, residual heat removal requirements are normally satisfied by steam bypass to the condenser. If the condenser is unavailable, steam can be released to the atmosphere through the safety valves or power operated relief valves. The capability to supply feedwater to the generators is normally provided by the operation of the Condensate and Feedwater Systems.

The Auxiliary Feedwater System provides a source of feedwater to the secondary side of the steam generators at times when the Feedwater System is not available, thereby maintaining heat sink capabilities of the steam generators. The Auxiliary Feedwater System provides heat removal until normal feedwater flow is restored or until an orderly cooldown to Reactor Coolant System conditions where the Residual Heat Removal System can be placed in service. The Auxiliary Feedwater System for each unit consists of two motor driven pumps, one turbine driven pump, a 110,000 gallon protected condensate storage tank, and associated common piping, redundant headers, valves, controls, and instrumentation. Although the flowpaths from the pumps to the steam generators include common piping, the configuration of the system provides two redundant flowpaths. The components in one flowpath are supplied by the H emergency bus, while the other is supplied by the J emergency bus. The auxiliary feedwater design basis accident is a loss of normal feedwater with offsite power available (the reactor coolant pumps running). The auxiliary feedwater flow required to remove the heat and cool the unit to residual heat removal conditions for this design basis case can be provided by any combination of two auxiliary feedwater pumps.

Refer to the Basis of Specification 4.8 for a discussion of auxiliary feedwater pump operability considerations.

Regarding the allowed outage times for auxiliary feedwater pump inoperability, Specification 3.6.E allows 7 days versus a 72 hour allowed outage time in Specification 3.6.F.1. The longer allowed outage time is based on the reduced decay heat following refueling and prior to reactor criticality.

In the unlikely event of loss of auxiliary feedwater capability on the affected unit (i.e., with all required auxiliary feedwater pumps inoperable or with both redundant flowpaths having an inoperable component or instrumentation), the required action is to immediately initiate action to restore operability of one inoperable pump or of the inoperable component or instrumentation in one flowpath. With such a loss of auxiliary feedwater capability, the unit is in a seriously degraded condition. In this condition, the unit should not be perturbed by any action, including a power change, which could result in a plant transient or trip. The seriousness of this condition requires that action be taken immediately to restore operability, where immediately means the required action should be pursued without delay and in a controlled manner. Under these circumstances, Specification 3.0.1 and all other required actions directing mode changes are suspended until one inoperable pump or the inoperable component or instrumentation in one flowpath is restored to operable status, because taking those actions could place the unit in a less safe condition.

Due to the occasional need to perform maintenance on common AFW components that would render all three AFW pumps on the opposite unit inoperable, e.g., the AFW pumps' full flow recirculation piping or the protected condensate storage tank, a 10-day allowed outage time is provided for opposite unit AFW cross-connect capability. The 10-day allowed outage time is supported by a risk analysis that demonstrates the associated risk is acceptably small for both CDF and LERF with considerable margin remaining. When entering the 10-day allowed outage time for the specific purpose of performing maintenance related to the operability of all three of the opposite unit's auxiliary feedwater pumps, the following compensatory measures are required to be in place:

- Additional AFW system maintenance, including associated water sources, or changes in plant configuration that would result in a risk significant configuration will be precluded;
- Weather conditions will be monitored and AFW maintenance affecting operability of the opposite unit cross-connect will not be scheduled if severe weather conditions are anticipated;
- The steam-driven AFW pump will be controlled as "Protected Equipment";
- The Technical Requirements Manual compensatory actions to address 10 CFR 50.65 (a)(4) fire risk related to AFW cross-connect unavailability, which include periodic walkdowns in relevant fire areas, will be taken; and
- The BDB/FLEX AFW pump will be pre-staged to provide AFW defense-in-depth comparable to the AFW cross-connect.

In the event of complete loss of electrical power to the station, residual heat removal would continue to be assured by the availability of either the turbine driven auxiliary feedwater pump or one of the motor driven auxiliary feedwater pumps and the 110,000-gallon protected condensate storage tank.

In the event of a fire or high energy line break which would render the auxiliary feedwater pumps inoperable on the affected unit, residual heat removal would continue to be assured by the availability of either the turbine driven auxiliary feedwater pump or one of the motor driven auxiliary feedwater pumps from the opposite unit. A minimum of two auxiliary feedwater pumps are required to be operable* on the opposite unit to ensure compliance with the design basis accident analysis assumptions, in that auxiliary feedwater can be delivered via the cross-connect, even if a single active failure results in the loss of one of the two pumps. In addition, the requirement for operability of the opposite unit's emergency power system is to ensure that auxiliary feedwater from the opposite unit can be supplied via the cross-connect in the event of a common-mode failure of all auxiliary feedwater pumps in the affected unit due to a high energy line break in the main steam valve house. Without this requirement, a single failure (such as loss of the shared backup diesel generator) could result in loss of power to the opposite unit's emergency buses in the event of a loss of offsite power, thereby rendering the cross-connect inoperable. The longer allowed outage time for the opposite unit's emergency power system is based on the low probability of a high energy line break in the main steam valve house coincident with a loss of offsite power.

The specified minimum water volume in the 110,000-gallon protected condensate storage tank is sufficient for 8 hours of residual heat removal following a reactor trip and loss of all offsite electrical power. If the protected condensate storage tank level is reduced to 60,000 gallons, the immediately available replenishment water in the 300,000-gallon condensate tank can be gravity-fed to the protected tank if required for residual heat removal. An alternate supply of feedwater to the auxiliary feedwater pump suctions is also available from the Fire Protection System Main in the auxiliary feedwater pump cubicle.

* excluding automatic initiation instrumentation

The five main steam code safety valves associated with each steam generator have a total combined capacity of 3,842,454 pounds per hour at their individual relieving pressure; the total combined capacity of all fifteen main steam code safety valves is 11,527,362 pounds per hour. The maximum steam flow at full power is approximately 11,444,000 pounds per hour. The combined capacity of the safety valves required by Specification 3.6 always exceeds the total steam flow corresponding to the maximum steady state power than can be obtained during three reactor coolant loop operation.

The availability of the auxiliary feedwater pumps, the protected condensate storage tank, and the main steam line safety valves adequately assures that sufficient residual heat removal capability will be available when required.

The limit on steam generator secondary side iodine-131 activity is based on limiting the dose at the site boundary following a postulated steam line break accident to the Regulatory Guide 1.183 limits. The accident analysis assumes the release of the entire contents of the faulted steam generator to the atmosphere.

REFERENCES

UFSAR Section 4, Reactor Coolant System

UFSAR Section 9.3, Residual Heat Removal System

UFSAR Section 10.3.1, Main Steam System

UFSAR Section 10.3.2, Auxiliary Steam System

UFSAR Section 10.3.5, Condensate and Feedwater Systems

UFSAR Section 10.3.8, Secondary Vent and Drain Systems

UFSAR Section 14.2.11, Loss of Normal Feedwater

UFSAR Section 14.3.2, Rupture of a Main Steam Pipe

UFSAR Appendix 14B, Effects of Piping System Breaks Outside Containment

TABLE 3.6-1A

UNIT 1
MAIN STEAM SAFETY VALVE LIFT SETTING

VALVE NUMBER	LIFT SETTING *#	ORIFICE SIZE
SV-MS-101A, B, C	1085 psig	7.07 sq. in.
SV-MS-102A, B, C	1095 psig	16 sq. in.
SV-MS-103A, B, C	1110 psig	16 sq. in.
SV-MS-104A, B, C	1120 psig	16 sq. in.
SV-MS-105A, B, C	1135 psig	16 sq. in.

TABLE 3.6-1B

UNIT 2
MAIN STEAM SAFETY VALVE LIFT SETTING

VALVE NUMBER	LIFT SETTING *#	ORIFICE SIZE
SV-MS-201A, B, C	1085 psig	7.07 sq. in.
SV-MS-202A, B, C	1095 psig	16 sq. in.
SV-MS-203A, B, C	1110 psig	16 sq. in.
SV-MS-204A, B, C	1120 psig	16 sq. in.
SV-MS-205A, B, C	1135 psig	16 sq. in.

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

\# The as found condition shall be ± 3% and the as left condition shall be ± 1%.

3.7 INSTRUMENTATION SYSTEMS

Operational Safety Instrumentation

Applicability

Applies to reactor and safety features instrumentation systems.

Objectives

To ensure the automatic initiation of the Reactor Protection System and the Engineered Safety Features in the event that a principal process variable limit is exceeded. and to define the limiting conditions for operation of the plant instrumentation and safety circuits necessary to ensure reactor and plant safety.

Specification

A. The Reactor Protection System instrumentation channels and interlocks shall be OPERABLE as specified in Table 3.7-1.

B. The Engineered Safeguards Actions and Isolation Function Instrumentation channels and interlocks shall be OPERABLE as specified in Tables 3.7-2 and 3.7-3, respectively.

C. The Engineered Safety Features initiation instrumentation setting limits shall be as stated in Table 3.7-4.

D. The explosive gas monitoring instrumentation channel shown in Table 3.7-5(a) shall be OPERABLE with its alarm setpoint set to ensure that the limits of Specification 3.11.A.1 are not exceeded.

   1. With an explosive gas monitoring instrumentation channel alarm setpoint less conservative than required by the above specification, declare the channel inoperable and take the action shown in Table 3.7-5(a).

2. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the action shown in Table 3.7-5(a). Exert best efforts to return the instruments to operable status within 30 days and, if unsuccessful, prepare and submit a Special Report to the Commission (Region II) to explain why the inoperability was not corrected in a timely manner.

E. Prior to the Reactor Coolant System temperature and pressure exceeding 350°F and 450 psig, respectively, the accident monitoring instrumentation listed in Table 3.7-6 shall be OPERABLE in accordance with the following:

1. With one required channel inoperable, either restore the inoperable channel to OPERABLE status within 30 days or submit a report to the NRC within the next 14 days. The report shall outline the cause of inoperability and the plans and schedule for restoring the inoperable channel to OPERABLE status.

2. With two required channels inoperable, either:

   a. Restore an inoperable channel(s) to OPERABLE status within 7 days or initiate the preplanned alternate method of monitoring the appropriate function and submit a report to the NRC within the next 14 days. The report shall outline the preplanned alternate method of monitoring the function, the cause of inoperability, and the plans and schedule for restoring an inoperable channel to OPERABLE status.

   b. If no preplanned alternate method of monitoring the function is available, restore an inoperable channel(s) to OPERABLE status within 7 days or be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours.

F. Two manual actuation trains of the Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Isolation Actuation Instrumentation shall be OPERABLE whenever:

- T_{avg} (average Reactor Coolant System (RCS) temperature) exceeds 200°F, or
- During movement of irradiated fuel.

Note: Automatic actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation is addressed as part of the Safety Injection Instrument Operating Conditions included in TS Table 3.7-2, "Engineered Safeguards Action Instrument Operating Conditions," Functional Unit No. 1.

1. For unit operation when T_{avg} exceeds 200°F:

   a. With one train inoperable, isolate the MCR/ESGR envelope normal ventilation within seven (7) days or be in at least HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

b. With two trains inoperable, isolate the MCR/ESGR envelope normal ventilation immediately or be in at least HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

2. During the movement of irradiated fuel assemblies:

   a. With one train inoperable, within seven (7) days either isolate the MCR/ESGR envelope normal ventilation or suspend movement of irradiated fuel assemblies.

   b. With two trains inoperable, immediately isolate the MCR/ESGR envelope normal ventilation or immediately suspend movement of irradiated fuel assemblies.

Basis

Instrument Operating Conditions

During plant operations, the complete instrumentation system will normally be in service. Reactor safety is provided by the Reactor Protection System, which automatically initiates appropriate action to prevent exceeding established limits. Safety is not compromised, however, by continuing operation with certain instrumentation channels out of service since provisions were made for this in the plant design. This specification outlines the limiting conditions for operation necessary to preserve the effectiveness of the Reactor Protection System when any one or more of the channels is out of service.

Almost all Reactor Protection System channels are supplied with sufficient redundancy to provide the capability for channel calibration and test at power. Exceptions are backup channels such as reactor coolant pump breakers. The removal of one trip channel on process control equipment is accomplished by placing that channel bistable in a tripped mode (e.g., a two-out-of-three circuit becomes a one-out-of-two circuit). The Nuclear Instrumentation System (NIS) channels are not intentionally placed in a tripped mode since the test signal is superimposed on the normal detector signal to test at power. Testing of the NIS power range channel requires: (a) bypassing the dropped-rod protection from NIS, for the channel being tested, (b) placing the $\Delta T/T_{avg}$ protection channel set that is being fed from the NIS channel in the trip mode, and (c) defeating the power mismatch section of T_{avg} control channels when the appropriate NIS channel is being tested. However, the Rod Position System and remaining NIS channels still provide the dropped-rod protection. Testing does not trip the system unless a trip condition exists in a concurrent channel.

Instrumentation has been provided to sense accident conditions and to initiate operation of the Engineered Safety Features.[1]

Safety Injection System Actuation

Protection against a loss-of-coolant or steam line break accident is provided by automatic actuation of the Safety Injection System (SIS) which provides emergency cooling and reduction of reactivity.

The loss-of-coolant accident is characterized by depressurization of the Reactor Coolant System and rapid loss of reactor coolant to the containment. The engineered safeguards instrumentation has been designed to sense these effects of the loss-of-coolant accident by detecting low pressurizer pressure to generate signals actuating the SIS active phase. The SIS active phase is also actuated by a high containment pressure signal brought about by loss of high enthalpy coolant to the containment. This actuation signal acts as a backup to the low pressurizer pressure actuation of the SIS and also adds diversity to protect against loss of coolant.

Signals are also provided to actuate the SIS upon sensing the effects of a steam line break accident. Therefore, SIS actuation following a steam line break is designed to occur upon sensing high differential steam pressure between the steam header and steam generator line or upon sensing high steam line flow in coincidence with low reactor coolant average temperature or low steam line pressure.

The increase in the extraction of RCS heat following a steam line break results in reactor coolant temperature and pressure reduction. For this reason, protection against a steam line break accident is also provided by low pressurizer pressure actuating safety injection.

Protection is also provided for a steam line break in the containment by actuation of SIS upon sensing high containment pressure.

SIS actuation injects highly borated fluid into the Reactor Coolant System in order to counter the reactivity insertion brought about by cooldown of the reactor coolant which occurs during a steam line break accident.

Containment Spray

The Engineered Safety Features also initiate containment spray upon sensing a high-high containment pressure signal. The containment spray acts to reduce containment pressure in the event of a loss-of-coolant or steam line break accident inside the containment. The containment spray cools the containment directly and limits the release of fission products by absorbing iodine should it be released to the containment.

Containment spray is designed to be actuated at a higher containment pressure than the SIS. Since spurious actuation of containment spray is to be avoided, it is initiated only on coincidence of high-high containment pressure sensed by 3 out of the 4 containment pressure signals.

Steam Line Isolation

Steam line isolation signals are initiated by the Engineered Safety Features closing the steam line trip valves. In the event of a steam line break, this action prevents continuous, uncontrolled steam release from more than one steam generator by isolating the steam lines on high-high containment pressure or high steam line flow with coincident low steam line pressure or low reactor coolant average temperature. Protection is afforded for breaks inside or outside the containment even when it is assumed that there is a single failure in the steam line isolation system.

Feedwater Line Isolation

The feedwater lines are isolated upon actuation of the SIS in order to prevent excessive cooldown of the Reactor Coolant System. This mitigates the effects of an accident such as a steam line break which in itself causes excessive coolant temperature cooldown. Feedwater line isolation also reduces the consequences of a steam line break inside the containment by stopping the entry of feedwater.

Auxiliary Feedwater System Actuation

The automatic initiation of auxiliary feedwater flow to the steam generators by instruments identified in Table 3.7-2 ensures that the Reactor Coolant System decay heat can be removed following loss of main feedwater flow. This is consistent with the requirements of the "TMI-2 Lessons Learned Task Force Status Report," NUREG-0578, item 2.1.7.b.

Setting Limits

1. The high containment pressure limit is set at about 8% of design containment pressure. Initiation of safety injection protects against loss of coolant[2] or steam line break[3] accidents as discussed in the safety analysis.
2. The high-high containment pressure limit is set at about 21% of design containment pressure. Initiation of containment spray and steam line isolation protects against large loss-of-coolant[2] or steam line break accidents[3] as discussed in the safety analysis.
3. The pressurizer low pressure setpoint for safety injection actuation is set substantially below system operating pressure limits. However, it is sufficiently high to protect against a loss-of-coolant accident as shown in the safety analysis.[2] The setting limit (in units of psig) is based on nominal atmospheric pressure.
4. The steam line high differential pressure limit is set well below the differential pressure expected in the event of a large steam line break accident as shown in the safety analysis.[3]
5. The high steam line flow differential pressure setpoint is constant at 40% full flow between no load and 20% load and increasing linearly to 110% of full flow at full load in order to protect against large steam line break accidents. The coincident low T_{avg} setting limit for SIS and steam line isolation initiation is set below its HOT SHUTDOWN value. The coincident steam line pressure setting limit is set below the full load operating pressure. The safety analysis shows that these settings provide protection in the event of a large steam line break.[3]

The methodology for determining the Setting Limits (SL) found in TS 3.7 was developed in Technical Report EE-0116. The Setting Limits must be chosen so that automatic protective action will correct an abnormal situation before the safety limit is exceeded. At Surry Power Station the Allowable Value (AV) serves as the Setting Limit such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the Channel Functional Test (which is also referred to as the Channel Operational Test or COT). As such, the Allowable Value differs from the Trip Setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the Setting Limit definition and ensure that the Safety Limit is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required.

Technical Report EE-0116 verifies that Surry's methodology for determining Allowable Values is in agreement with the intent of ISA Standard S67.04, Methods 1 and 2. In addition, it is Dominion's position that the Analytical Limit will be protected if:

1. the distance between the Trip Setpoint and the Analytical Limit is equal to or greater than the Total Loop Uncertainty for that channel <u>and</u>

2. the distance between the Allowable Value and the Analytical Limit is equal to or greater than the non-COT error components of the Total Loop Uncertainty <u>and</u>

3. the distance between the Trip Setpoint and the Allowable Value is equal to the COT error components of the Total Loop Uncertainty without any excessive margin included.

Both the Trip Setpoint and the Allowable Value must be properly established in order to adequately protect the Analytical Limit.

Accident Monitoring Instrumentation

The primary purpose of accident monitoring instrumentation is to display unit parameters that provide information required by the control room operators during and following accident conditions. In response to NUREG-0737 and Regulatory Guide (RG) 1.97, Revision 3, a programmatic approach was developed in defining the RG 1.97-required equipment for Surry. The Surry RG 1.97 program review examined existing instrumentation with respect to the RG 1.97 design and qualification requirements. The operability of RG 1.97 instrumentation ensures that sufficient information is available on selected unit parameters to monitor and assess unit status and response during and following an accident. The availability of accident monitoring instrumentation is important so that the consequences of corrective actions can be observed and the need for and magnitude of further actions can be determined.

RG 1.97 applied a graded approach to post-accident indication by using a matrix of variable types versus variable categories. RG 1.97 delineates design and qualification criteria for the instrumentation used to measure five variable types (Types A, B, C, D, and E). These criteria are divided into three separate categories (Categories 1, 2, and 3), providing a graded approach that depended on the importance to safety of the measurement of a specific variable. Category 1 variables, listed in Table 3.7-6, are defined as follows:

Category 1 - are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions,
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release, and
- Provide information regarding the release of radioactive materials to allow early indication of the need to initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

The RG 1.97 criteria on redundancy requirements apply to Category 1 variables only and address single-failure criteria and supporting features, including power sources. Failures of the instrumentation, its supporting features, and/or its power source resulting in less than the required number of channels necessitate entry into the required actions.

The 30 day allowed outage time applies when one (or more) function(s) in Table 3.7-6 has one required channel that is inoperable. The 30 day allowed outage time to restore one inoperable required channel to OPERABLE status is appropriate considering the remaining channel is OPERABLE, the passive nature of the instrument (i.e., no automatic action is assumed to occur from this instrumentation), and the low probability of an event requiring accident monitoring instrumentation during this interval. The 7 day allowed outage time applies when one (or more) function(s) in Table 3.7-6 has two required channels that are inoperable. The 7 day allowed outage time to restore one of the two inoperable required channels to OPERABLE status is appropriate based on providing a reasonable time for the repair and the low probability of an event requiring accident monitoring instrument operation. Long-term operation with two required channels inoperable in a function and with an alternate indication is not acceptable because the alternate indication may not fully meet the performance qualification requirements applied to the accident monitoring instrumentation. Requiring restoration of one of the two inoperable channels limits the risk that the accident monitoring instrumentation function could be in a degraded condition should an accident occur. If there is no preplanned alternate, the 7 day allowed outage time is followed by a requirement to be in HOT SHUTDOWN within the next 6 hours and be less than 350°F and 450 psig within the following 12 hours. If the 30 day allowed outage time or 7 day allowed outage time to restore an inoperable channel to OPERABLE status is exceeded and either a redundant channel or a preplanned alternate method of monitoring is OPERABLE, a report to the NRC within the next 14 days is required. The report to the NRC in lieu of a shutdown is appropriate because the instrument functional capability has not been lost and given the low likelihood of unit conditions that would require the information provided by the accident monitoring instrumentation.

Note that the Categories 2 and 3 RG 1.97 variables are addressed in a licensee controlled document and are defined as follows:

Category 2 - provides less stringent requirements and generally applies to instrumentation designated for indicating system operating status.

Category 3 - is the least stringent and is applied to backup and diagnostic instrumentation.

Explosive Gas Monitoring

Instrumentation is provided for monitoring (and controlling) the concentrations of potentially explosive gas mixtures in the Waste Gas Holdup System. The operability and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

Non-Essential Service Water Isolation System

The operability of this functional system ensures that adequate intake canal inventory can be maintained by the Emergency Service Water Pumps. Adequate intake canal inventory provides design service water flow to the recirculation spray heat exchangers and other essential loads (e.g., control room area chillers, charging pump lube oil coolers) following a design basis loss of coolant accident with a coincident loss of offsite power. This system is common to both units in that each of the two trains will actuate equipment on each unit.

Clarification of Operator Actions

The Operator Actions associated with Functional Units 10 and 16 on Table 3.7-1 require the unit to be reduced in power to less than the P-7 setpoint (10%) if the required conditions cannot be satisfied for either the P-8 or P-7 permissible bypass conditions. The requirement to reduce power below P-7 for a P-8 permissible bypass condition is necessary to ensure consistency with the out of service and shutdown action times assumed in the WCAP-10271 and WCAP-14333P risk analyses by eliminating the potential for a scenario that would allow sequential entry into the Operator Actions (i.e., initial entry into the Operator Action with a reduction in power to below P-8, followed by a second entry into the Operator Action with a reduction in power to below P-7). This scenario would permit sequential allowed outage time periods that may result in an additional 72 hours that was not assumed in the risk analysis to place a channel in trip or to place the unit in a condition where the protective function was not necessary.

Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Isolation Actuation Instrumentation

BACKGROUND - The MCR/ESGR Envelope Isolation Function provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity. During normal operation, the Service Building Ventilation System and the Main Control Room (MCR) and Emergency Switchgear Room (ESGR) Air Conditioning System (ACS) provide unfiltered makeup air and cooling, respectively, for the MCR/ESGR envelope. Upon receipt of a MCR/ESGR Envelope Isolation Actuation signal from either unit's Safety Injection (SI) signal or from manual actuation, the following actions occur: 1) the MCR/ESGR envelope normal ventilation intake and exhaust ducts are isolated to prevent unfiltered makeup air from entering the MCR/ESGR envelope, 2) the normal ventilation supply and exhaust fans are shut down, and 3) adjacent area ventilation fans are shut down. The MCR/ESGR Emergency Ventilation System (EVS) can then be placed into service when required to provide a source of filtered makeup air to the MCR/ESGR envelope. The MCR/ESGR EVS is described in the Bases for TS 3.21, "Main Control Room/Emergency Switchgear Room (MCR/ESGR) Emergency Ventilation System (EVS)."

There are two independent and redundant trains of manual actuation instrumentation for MCR/ESGR Envelope Isolation. Each manual actuation train consists of two damper actuation switches and the interconnecting wiring to the actuation circuitry as follows: 1) normal ventilation dampers 1-VS-MOD-103A (supply) and 1-VS-MOD-103D (exhaust), and 2) normal ventilation dampers 1-VS-MOD-103C (supply) and 1-VS-MOD-103B (exhaust). Automatic actuation of the MCR/ESGR Envelope Isolation Function is addressed as part of the SI system in Table 3.7-2, "Engineered Safeguards

Action Instrument Operating Conditions," Functional Unit No. 1.

APPLICABLE SAFETY ANALYSES - The MCR/ESGR envelope must be kept habitable for the operators stationed there during accident recovery and post accident operations. The MCR/ESGR Envelope Isolation Actuation Instrumentation automatically acts to terminate the supply of unfiltered outside air on an SI signal and is manually actuated for a Fuel Handling Accident (FHA).

In REACTOR OPERATION conditions where T_{avg} exceeds 200°F, the safety analyses for a Loss of Coolant Accident, Main Steam Line Break, and a Steam Generator Tube Rupture assume automatic isolation of the MCR/ESGR envelope on an SI signal and manual initiation of filtered air flow provided by the MCR/ESGR EVS within 1 hour. No credit is taken for the pressurization provided by the MCR/ESGR EVS. The safety analysis for a FHA assumes manual isolation of the MCR/ESGR envelope upon indication that a FHA has occurred and manual initiation of the MCR/ESGR EVS to supply filtered air flow within 1 hour. MCR/ESGR envelope isolation is not credited for a Locked Rotor Accident. Total ventilation inflow of 1500 cfm is assumed: 1000 cfm of filtered emergency supply fan flow plus 500 cfm of unfiltered inleakage.

During the movement of irradiated fuel, the accident analysis assumes manual isolation of the MCR/ESGR envelope upon indication that a FHA has occurred and manual initiation of the MCR/ESGR EVS to supply filtered air flow within 1 hour.

Normal ventilation is assumed during a toxic gas or smoke incident. MCR/ESGR envelope isolation and manual initiation of filtered air from the MCR/ESGR EVS is at the discretion of the MCR operators to mitigate the consequences of these events.

The MCR/ESGR Envelope Isolation Actuation Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION (LCO) - The LCO requirements ensure that instrumentation necessary to initiate MCR/ESGR envelope isolation is OPERABLE.

1. Manual Actuation

   The LCO requires two trains to be OPERABLE. The operator can initiate MCR/ESGR envelope isolation at any time by closing dampers 1-VS-MOD-103A (supply) and 1-VS-MOD-103D (exhaust) [Train A] or 1-VS-MOD-103C (supply) and 1-VS-MOD-103B (exhaust) [Train B] from the MCR. This action will cause actuation of components in the same manner as the automatic actuation signal, i.e., isolate the normal ventilation supply and exhaust ducts, trip the normal ventilation supply and exhaust fans, and trip the adjacent non-safety-related Turbine/Service Building ventilation fans.

   The LCO for manual actuation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability. Each train consists of two damper control switches and the interconnecting wiring to the actuation circuitry.

2. Safety Injection

   Refer to Table 3.7-2, "Engineered Safeguards Action Instrument Operating Conditions," Functional Unit No. 1, for all automatic initiating functions and requirements.

APPLICABILITY - The MCR/ESGR Envelope Isolation Function must be OPERABLE in REACTOR OPERATION conditions where T_{avg} exceeds 200°F to provide the required MCR/ESGR envelope isolation assumed in the applicable safety analyses. In COLD SHUTDOWN and REFUELING OPERATION, when no fuel movement involving irradiated fuel is taking place, there are no requirements for MCR/ESGR Envelope Isolation Actuation Instrumentation operability consistent with the safety analyses assumptions applicable in these REACTOR OPERATION conditions.

In addition, the Manual Actuation function of the MCR/ESGR Envelope Isolation Actuation Instrumentation is required to be OPERABLE when moving irradiated fuel.

ACTIONS

3.7.F.1.a

This TS requirement applies to the failure of one manual MCR/ESGR Envelope Isolation Actuation Instrumentation train.

If one train is inoperable, seven (7) days are permitted to restore it to OPERABLE status. In this condition, the remaining required OPERABLE manual MCR/ESGR Envelope Isolation Actuation Instrumentation train is adequate to perform the MCR/ESGR envelope isolation function. However, the overall reliability is reduced because a failure in the OPERABLE train could result in loss of MCR/ESGR envelope isolation function. The 7 day Allowed Outage Time is based on the low probability of a DBA occurring during this time period, and the ability of the remaining train to provide the required capability.

If the train cannot be restored to OPERABLE status, the normal ventilation to the MCR/ESGR envelope must be isolated. This accomplishes the manual MCR/ESGR envelope isolation function and places the unit in a conservative mode of operation. If the Required Action and associated Allowed Outage Time for Action Statement 3.7.F.1.a have not been met and T_{avg} exceeds 200°F, the unit must be brought to a REACTOR OPERATION condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours. The completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

3.7.F.1.b

This TS requirement applies to the failure of two manual MCR/ESGR Envelope Isolation Actuation Instrumentation trains.

The Required Action is to isolate the normal ventilation to the MCR/ESGR envelope immediately. This accomplishes the manual MCR/ESGR envelope isolation function that may have been lost and places the unit in a conservative mode of operation. If the

Required Action and associated Allowed Outage Time for Action Statement 3.7.F.1.b have not been met and T_{avg} exceeds 200°F, the unit must be brought to a REACTOR OPERATION condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within the following 30 hours. The completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

3.7.F.2.a

This TS requirement applies to the failure of one manual MCR/ESGR Envelope Isolation Actuation Instrumentation train when irradiated fuel assemblies are being moved. Either the normal ventilation to MCR/ESGR envelope must be isolated or movement of irradiated fuel assemblies must be suspended within 7 days to reduce the risk of accidents that would require manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation.

3.7.F.2.b

This TS requirement applies to the failure of two manual MCR/ESGR Envelope Isolation Actuation Instrumentation trains when irradiated fuel assemblies are being moved. Either the normal ventilation to MCR/ESGR envelope must be isolated or movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation.

References

(1) UFSAR - Section 7.5

(2) UFSAR - Section 14.5

(3) UFSAR - Section 14.3.2

(4) UFSAR - Section 9.13

(5) UFSAR - Section 14.4.1

TABLE 3.7-1
REACTOR TRIP
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Action
1. Manual	2	2	1		1
2. Nuclear Flux Power Range*	4	3	2	Low trip setting at P-10	2
3. Nuclear Flux Intermediate Range*	2	2	1	P-10	3
4. Nuclear Flux Source Range*				P-6	
a. Below P-6 - Note A	2	2	1		4
b. Shutdown - Note B	2	1	0		5
5. Overtemperature ΔT*	3	2	2		6
6. Overpower ΔT**	3	2	2		6
7. Low Pressurizer Pressure*	3	2	2	P-7	7
8. Hi Pressurizer Pressure*	3	2	2		6

Note A - With the reactor trip breakers closed and the control rod drive system capable of rod withdrawal.

Note B - With the reactor trip breakers open.

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* There is a Safety Analysis Limit associated with this Reactor Trip function. If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

** If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-1
REACTOR TRIP
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Action
9. Pressurizer-Hi Water Level*	3	2	2	P-7	7
10. Low Flow*	3/loop	2/loop in each operating loop	2/loop in any operating loop	P-8	7
			2/loop in any 2 operating loops	P-7	7
11. Turbine Trip					
a. Stop valve closure	4	1	4	P-7	7
b. Low fluid oil pressure	3	2	2	P-7	7
12. Lo-Lo Steam Generator Water Level*	3/loop	2/loop in each operating loop	2/loop in any operating loops		6
13. Underfrequency 4KV Bus	3-1/bus	2	2	P-7	7
14. Undervoltage 4KV Bus	3-1/bus	2	2	P-7	7
15. Safety Injection (SI) Input From ESF	2	2	1		11
16. Reactor Coolant Pump Breaker Position	1/breaker	1/breaker per operating loop	1 2	P-8 P-7	9 9

* There is a Safety Analysis Limit associated with this Reactor Trip function. If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

** If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-1
REACTOR TRIP
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Action
17. Low steam generator water** level with steam/feedwater flow mismatch	2/loop-level and 2/loop-flow mismatch	1/loop-level and 2/loop-flow mismatch or 2/loop-level and 1/loop-flow mismatch	1/loop-level coincident with 1/loop-flow mismatch in same loop		6
18. a. Reactor Trip Breakers	2	2	1		8
b. Reactor Trip Bypass Breakers - Note C	2	1	1		
19. Automatic Trip Logic	2	2	1		11
20. Reactor Trip System Interlocks - Note D					
a. Intermediate range neutron flux, P-6	2	2	1		13
b. Low power reactor trips block, P-7					
Power range neutron flux, P-10	4	3	2		13
and					
Turbine impulse pressure	2	2	1		13
c. Power range neutron flux, P-8*	4	3	2		13
d. Power range neutron flux, P-10	4	3	2		13
e. Turbine impulse pressure	2	2	1		13

Note C - With the Reactor Trip Breaker open for surveillance testing in accordance with Specification Table 4.1-1 (Item 30)
Note D - Reactor Trip System Interlocks are described in Table 4.1-A

* There is a Safety Analysis Limit associated with this Reactor Trip function. If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

** If during calibration the setpoint is found to be conservative with respect to the Limiting Safety System Setting but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-1 (Continued)

TABLE NOTATION

ACTION STATEMENTS

ACTION 1. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requir.ment, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN and open the reactor trip breakers within the next 6 hours.

ACTION 2. With the number of OPERABLE channels equal to the Minimum OPERABLE Channels requirement, REACTOR CRITICAL and POWER OPERATION may proceed provided the following conditions are satisfied:

1. The inoperable channel is placed in the tripped condition within 72 hours.
2. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of the redundant channel(s) per Specification 4.1.
3. Either, THERMAL POWER is restricted to ≤ 75% of RATED POWER and the Power Range, Neutron Flux trip setpoint is reduced to ≤ 85% of RATED POWER within 78 hours; or, the QUADRANT POWER TILT is monitored at least once per 12 hours.

TABLE 3.7-1 (Continued)

4. The QUADRANT POWER TILT shall be determined to be within the limit when above 75 percent of RATED POWER with one Power Range Channel inoperable by using the moveable incore detectors to confirm that the normalized symmetric power distribution, obtained from 2 sets of 4 symmetric thimble locations or a full-core flux map, is consistent with the indicated QUADRANT POWER TILT at least once per 12 hours.

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

ACTION 3. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement and with the THERMAL POWER level:

a. Below the P-6 (Block of Source Range Reactor Trip) setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint.

b. Above the P-6 (Block of Source Range Reactor Trip) setpoint, but below 11% of RATED POWER, within 24 hours, decrease power below P-6 or increase THERMAL POWER above 11% of RATED POWER.

c. Above 11% of RATED POWER, POWER OPERATION may continue.

ACTION 4. With the number of channels OPERABLE one less than required by the Minimum OPERABLE Channels requirement and with the THERMAL POWER level:

a. Below P-6, (Block of Source Range Reactor Trip) setpoint, immediately suspend reactivity changes that are more positive than necessary to meet the required shutdown margin or refueling boron concentration limit and restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour. With two Source Range Channels inoperable, open the reactor trip breakers immediately. Two Source Range channels must be OPERABLE prior to increasing THERMAL POWER above the P-6 setpoint.

b. Above P-6, operation may continue.

ACTION 5. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, verify compliance with the Shutdown Margin requirements within 1 hour and at least once per 12 hours thereafter.

ACTION 6. With the number of OPERABLE channels less than the Total Number of Channels, REACTOR CRITICAL and POWER OPERATION may proceed provided the following conditions are satisfied:

1. The inoperable channel is placed in the tripped condition within 72 hours.

2. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels per Specification 4.1.

If the conditions are not satisfied in the time permitted, be in at least HOT SHUTDOWN within 6 hours.

TABLE 3.7-1 (Continued)

ACTION 7. With the number of OPERABLE channels less than the Total Number of Channels, REACTOR CRITICAL and POWER OPERATION may proceed provided the following conditions are satisfied:

1. The inoperable channel is placed in the tripped condition within 72 hours.
2. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing per Specification 4.1.

If the conditions are not satisfied in the time permitted, reduce power to less than the P-7 setpoint within the next 6 hours.

ACTION 8.A. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within 6 hours (Reference: WCAP-15376-P-A). In conditions of operation other than REACTOR CRITICAL or POWER OPERATIONS, with the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour. However, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.1 provided the other channel is OPERABLE, or one reactor trip breaker may be bypassed for up to 4 hours for concurrent surveillance testing of the Reactor trip breaker and automatic trip logic provided the other train is OPERABLE.

8.B. With one of the diverse trip features (undervoltage or shunt trip device) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and apply Action 8.A. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required

TABLE 3.7-1 (Continued)

ACTION 9.	With one channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or reduce THERMAL POWER to below the P-7 (Block of Low Reactor Coolant Pump Flow and Reactor Coolant Pump Breaker Position) setpoint within the next 6 hours.
ACTION 10.	Deleted
ACTION 11.	With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within 6 hours. In conditions of operation other than REACTOR CRITICAL or POWER OPERATIONS, with the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour. However, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.1 provided the other channel is OPERABLE.
ACTION 12.	Deleted
ACTION 13.	With the number of OPERABLE channels less than the Minimum OPERABLE Channels requirement, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or be in at least HOT SHUTDOWN within the next 6 hours.

TABLE 3.7-2
ENGINEERED SAFEGUARDS ACTION
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
1. SAFETY INJECTION (SI)					
a. Manual	2	2	1		21
b. High containment pressure*	4	3	3		17
c. High differential pressure between any steam line and the steam header*	3/steam line	2/steam line	2/steam line on any steam line	Primary pressure less than 2010 psig, except when reactor is critical	20
d. Pressurizer low-low pressure*	3	2	2	Primary pressure less than 2010 psig, except when reactor is critical	20
e. High steam flow in 2/3 steam lines coincident with low T_{avg} or low steam line pressure*					
1) Steam line flow*	2/steam line	1/steam line	1/steam line any two lines	Reactor coolant T_{avg} less than 545° during heatup and cooldown	20
2) T_{avg}*	1/loop	1/loop any two loops	1/loop any two loops	Reactor coolant T_{avg} less than 545° during heatup and cooldown	20
3) Steam line pressure*	1/line	1/line any two loops	1/line any two loops	Reactor coolant T_{avg} less than 545° during heatup and cooldown	20
f. Automatic actuation logic	2	2	1		14

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-2 (Continued)
ENGINEERED SAFEGUARDS ACTION
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
2. CONTAINMENT SPRAY					
a. Manual	1 set	1 set	1 set♦		15
b. High containment pressure (Hi-Hi)*	4	3	3		17
c. Automatic actuation logic	2	2	1		14
3. AUXILIARY FEEDWATER					
a. Steam generator water level low-low*					
1) Start motor driven pumps	3/steam generator	2/steam generator	2/steam generator any 1 generator		20
2) Starts turbine driven pump	3/steam generator	2/steam generator	2/steam generator any 2 generators		20
b. RCP undervoltage starts turbine driven pump	3	2	2		20
c. Safety injection - start motor driven pumps	See #1 above (all SI initiating functions and requirements)				
d. Station blackout - start motor driven pumps	1/bus 2 transfer buses/unit	1/bus 2 transfer buses/unit	2		24

♦ Must actuate 2 switches simultaneously

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-2 (Continued)
ENGINEERED SAFEGUARDS ACTION
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
3. AUXILIARY FEEDWATER (continued)					
e. Trip of main feedwater pumps - start motor driven pumps	2/MFW pump	1/MFW pump	2-1 each MFW pump		24
f. Automatic actuation logic	2	2	1		22
4. LOSS OF POWER					
a. 4.16 kv emergency bus undervoltage (loss of voltage)	3/bus	2/bus	2/bus		26
b. 4.16 kv emergency bus undervoltage (degraded voltage)	3/bus	2/bus	2/bus		26
c. 4.16 kv emergency bus negative sequence voltage (open phase)	3/bus	2/bus	2/bus		27
5. NON-ESSENTIAL SERVICE WATER ISOLATION					
a. Low intake canal level*	4	3	3		20
b. Automatic actuation logic	2	2	1		14
6. ENGINEERED SAFEGAURDS ACTUATION INTERLOCKS - Note A					
a. Pressurizer pressure, P-11	3	2	2		23
b. Low-low T_{avg}, P-12	3	2	2		23
c. Reactor trip, P-4	2	2	1		24
7. RECIRCULATION MODE TRANSFER					
a. RWST Level - Low-Low*	4	3	2		25
b. Automatic Actuation Logic and Actuation Relays	2	2	1		14

Note A - Engineered Safeguards Actuation Interlocks are described in Table 4.1-A

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-2 (Continued)
ENGINEERED SAFEGUARDS ACTION
INSTRUMENT OPERATING CONDITIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
8. RECIRCULATION SPRAY					
a. RWST Level - Low Coincident with High High Containment Pressure*	4	3	2		20
b. Automatic Actuation Logic and Actuation Relays	2	2	1		14

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-3

INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
1. CONTAINMENT ISOLATION					
a. Phase I					
1) Safety Injection (SI)	See Item #1, Table 3.7-2 (all SI initiating functions and requirements)				
2) Automatic initiation logic	2	2	1		14
3) Manual	2	2	1		21
b. Phase 2					
1) High containment pressure*	4	3	3		17
2) Automatic actuation logic	2	2	1		14
3) Manual	2	2	1		21
c. Phase 3					
1) High containment pressure (Hi-Hi setpoint)*	4	3	3		17
2) Automatic actuation logic	2	2	1		14
3) Manual	1 set	1 set	1 set♦		15
2. STEAMLINE ISOLATION					
a. High steam flow in 2/3 lines coincident with 2/3 low T_{avg} or 2/3 low steam pressures*	See Item #1.e Table 3.7-2 for operability requirements				

♦ Must actuate 2 switches simultaneously

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-3 (Continued)
INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

Functional Unit	Total Number Of Channels	Minimum OPERABLE Channels	Channels To Trip	Permissible Bypass Conditions	Operator Actions
STEAMLINE ISOLATION (continued)					
b. High containment pressure (Hi-Hi setpoint)*	4	3	3		17
c. Manual	1/steamline	1/steamline	1/steamline		21
d. Automatic actuation logic	2	2	1		22
3. TURBINE TRIP AND FEEDWATER ISOLATION				When all MFRV, SG FWIV & associated bypass valves are closed & deactivated or isolated by manual valves.	
a. Steam generator water-level high-high*	3/steam generator	2/steam generator	2/in any one steam generator		20
b. Automatic actuation logic and actuation relay	2	2	1		22
c. Safety injection	See Item #1 Table 3.7-2 (all SI initiating functions and requirements)				

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLES 3.7-2 AND 3.7-3

TABLE NOTATIONS

ACTION 14. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the next 30 hours. One channel may be bypassed for up to 8 hours for surveillance testing per Specification 4.1, provided the other channel is OPERABLE.

ACTION 15. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 30 hours.

ACTION 16. Deleted

ACTION 17. With the number of OPERABLE channels one less than the Total Number of Channels, REACTOR CRITICAL and POWER OPERATION may proceed provided the inoperable channel is placed in the tripped condition within 72 hours and the Minimum OPERABLE Channels requirement is met. One additional channel may be bypassed for up to 12 hours for surveillance testing per Specification 4.1.

ACTION 18. Deleted

ACTION 19. Deleted

ACTION 20. With the number of OPERABLE channels less than the Total Number of Channels, REACTOR CRITICAL and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 72 hours.

b. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels per Specification 4.1.

If the conditions are not satisfied in the time permitted, be in HOT SHUTDOWN within the next 6 hours and reduce RCS temperature & pressure to less than 350°F/450 psig, respectively in the following 12 hours.

TABLES 3.7-2 ANDS 3.7-3 (Continued)

TABLE NOTATIONS

ACTION 21. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 22. With the number of OPERABLE channels one less than the Minimum OPERABLE Channels requirement, restore the inoperable channel to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 6 hours and reduce pressure and temperature to less than 450 psig and 350° within the following 12 hours; however, one channel may be bypassed for up to 8 hours for surveillance testing per Specification 4.1 provided the other channel is OPERABLE.

ACTION 23. With the number of OPERABLE channels less than the Minimum OPERABLE Channels requirement, within one hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or be in at least HOT SHUTDOWN within the next 6 hours.

ACTION 24. With the number of OPERABLE channels less than the Total Number of Channels, restore the inoperable channels to OPERABLE status within 48 hours or reduce pressure and temperature to less than 450 psig and 350°F within the next 12 hours.

ACTION 25. With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the bypassed condition within 72 hours or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. One additional channel may be bypassed for up to 12 hours for surveillance testing per Specification 4.1.

ACTION 26. With the number of OPERABLE channels less than the Total Number of Channels, the associated Emergency Diesel Generator may be considered OPERABLE provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped conditions within 72 hours.

b. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels per Specification 4.1.

If the conditions are not satisfied, declare the associated EDG inoperable.

TABLES 3.7-2 ANDS 3.7-3 (Continued)

TABLE NOTATIONS

ACTION 27. With the number of OPERABLE channels less than the Total Number of Channels, the negative sequence voltage (open phase) protection function may be considered OPERABLE provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 72 hours.

Note: Action 27.a does not apply if the negative sequence voltage (open phase) protection function cannot be performed.

b. The Minimum OPERABLE Channels requirement is met; however, the inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels per Specification 4.1.

c. If the negative sequence voltage (open phase) protection function cannot be performed (e.g., the Potential Transformer Blocking Device is tripped), the negative sequence voltage (open phase) protection function does not have to be declared inoperable provided verification is performed at least once per 24 hours that an open phase condition does not exist on the primary side of transformer TX-2, transformer TX-4, and the Reserve Station Service Transformers, as well as the Unit l/Unit 2 Main Step-up Transformers when power is supplied by the dependable alternate source. The negative sequence voltage (open phase) protection function shall be restored within 72 hours.

If the conditions are not satisfied, restore the protection function within 7 days or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

TABLE 3.7-4

ENGINEERED SAFETY FEATURE SYSTEM INITIATION LIMITS INSTRUMENT SETTING

No.	Functional Unit	Channel Action	Setting Limit
1	High Containment Pressure (High Containment Pressure Signal)*	a) Safety Injection b) Containment Vacuum Pump Trip c) High Press. Containment Isolation d) Safety Injection Containment Isolation e) F.W. Line Isolation	≤ 18.5 psia
2	High-High Containment Pressure (High-High Containment Pressure Signals)*	a) Containment Spray b) Recirculation Spray c) Steam Line Isolation d) High- High Press. Containment Isolation	≤ 24 psia
3	Pressurizer Low-Low Pressure*	a) Safety Injection b) Safety Injection Containment Isolation c) F.W. Line Isolation	≥ 1,770 psig
4	High Differential Pressure Between Steam Line and the Steam Line Header*	a) Safety Injection b) Safety Injection Containment Isolation c) F.W. Line Isolation	≤ 135 psid
5	High Steam Flow in 2/3 Steam Lines*	a) Safety Injection	≤ 40% (at zero load) of full steam flow ≤ 40% (at 20% load) of full steam flow ≤ 110% (at full load) of full steam flow
		b) Steam Line Isolation c) Safety Injection Containment Isolation d) F.W. Line Isolation	
	Coincident with Low T_{avg} or Low Steam Line Pressure*		≥ 541°F T_{avg} ≥ 510 psig steam line pressure

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-4

ENGINEERED SAFETY FEATURE SYSTEM INITIATION LIMITS INSTRUMENT SETTING

No.	Functional Unit	Channel Action	Setting Limit
6	AUXILIARY FEEDWATER		
	a. Steam Generator Water Level Low-Low*	Aux. Feedwater Initiation S/G Blowdown Isolation	≥ 16.0% narrow range
	b. RCP Undervoltage	Aux. Feedwater Initiation	≥ 70% nominal
	c. Safety Injection	Aux. Feedwater Initiation	All S.I. setpoints
	d. Station Blackout	Aux. Feedwater Initiation	≥ 46.7% nominal
	e. Main Feedwater Pump Trip	Aux. Feedwater Initiation	N.A.
7	LOSS OF POWER		
	a. 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	Emergency Bus Separation and Diesel start	≥ 2975 volts and ≤ 3265 volts with a 2 (+5, -0.1) second time delay
	b. 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	Emergency Bus Separation and Diesel start	≥ 3830 volts and ≤ 3881 volts with a 60 (±3.0) second time delay (Non CLS, Non SI) 7 (±0.35) second time delay (CLS or SI Conditions)
	c. 4.16 KV Emergency Bus Negative Sequence Voltage (Open Phase)	Emergency Bus Separation and Diesel start	≤ 7% voltage imbalance
8	NON-ESSENTIAL SERVICE WATER ISOLATION		
	a. Low Intake Canal Level*	Isolation of Service Water flow to non-essential loads	23 feet-5.85 inches
9	RECIRCULATION MODE TRANSFER		
	a. RWST Level-Low-Low*	Initiation of Recirculation Mode Transfer System	≥ 12.7% ≤ 14.3%
10	TURBINE TRIP AND FEEDWATER ISOLATION		
	a. Steam Generator Water Level High-High*	Turbine Trip Feedwater Isolation	≤ 76% narrow range

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-4

ENGINEERED SAFETY FEATURE SYSTEM INITIATION LIMITS INSTRUMENT SETTING

No.	Functional Unit	Channel Action	Setting Limit
11	RWST Level Low (coincident with High High Containment Pressure)*	Recirculation Spray Pump Start	$\geq$ 59% $\leq$ 61%

* There is a Safety Analysis Limit associated with this ESF function. If during calibration the setpoint is found to be conservative with respect to the Setting Limit but outside its predefined calibration tolerance, then the channel shall be brought back to within its predefined calibration tolerance before returning the channel to service. The calibration tolerances are specified in a document controlled under 10 CFR 50.59.

TABLE 3.7-5
AUTOMATIC FUNCTIONS
OPERATED FROM RADIATION MONITORS ALARM

Monitor Channel	Automatic Function At Alarm Conditions	Monitoring Requirements	Alarm Setpoint μ Ci/cc
1. Component cooling water radiation monitors	Shuts surge tank vent valve HCV-CC-100	See Specification 3.13	Twice Background

TABLE 3.7-5(a)

EXPLOSIVE GAS MONITORING INSTRUMENTATION

Instrument	Total No. of Channels	Minimum OPERABLE Channels	Action
1. Waste Gas Holdup System Explosive Gas Monitoring System Oxygen Monitor	1	1	1

ACTION 1 - With the number of channels OPERABLE less than required by the minimum OPERABLE channels requirement, operation of this waste gas holdup system may continue provided grab samples are collected (1) at least once per 4 hours during degassing operations to the waste gas decay tank and (2) at least once per 24 hours during other operations. Samples shall be analyzed within 4 hours after collection.

TABLE 3.7-6
ACCIDENT MONITORING INSTRUMENTATION
NOTE: Separate entry into Specification 3.7.E is allowed for each Function.

Function	Required Channels
1. Auxiliary Feedwater Flow	2
2. Inadequate Core Cooling	
a. Reactor Vessel Coolant Level	2
b. Reactor Coolant System Subcooling Margin	2
c. Core Exit Temperature	2 (a)
3. Containment Pressure (Wide Range)	2
4. Containment Pressure	2
5. Containment Sump Water Level (Wide Range)	2
6. Containment Area Radiation (High Range)	2
7. Power Range Neutron Flux	2 (b)
8. Source Range Neutron Flux	2 (b)
9. Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	2
10. RCS Cold Leg Temperature (Wide Range)	2
11. RCS Pressure (Wide Range)	2
12. Penetration Flow Path Containment Isolation Valve Position	2 per penetration flow path (c)(d)
13. Pressurizer Level	2
14. Steam Generator (SG) Water Level (Wide Range)	2
15. SG Water Level (Narrow Range)	2 per SG
16. SG Pressure	2 per SG
17. Emergency Condensate Storage Tank Level	2
18. High Head Safety Injection Flow to Cold Leg	2

(a) A minimum of 2 core exit thermocouples per quadrant are required for the channel to be OPERABLE.

(b) This indication is provided by the Gammametric channels.

(c) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(d) Only one position indication channel is required for penetration flow paths with only one installed control room indication channel.

3.8 CONTAINMENT

Applicability

Applies to the integrity and operating pressure of the reactor containment.

Objective

To define the limiting operating conditions of the reactor containment.

Specification

A. CONTAINMENT INTEGRITY

1. CONTAINMENT INTEGRITY, as defined in TS Section 1.0, shall be maintained whenever the Reactor Coolant System temperature exceeds 200°F.

   a. Without CONTAINMENT INTEGRITY, re-establish CONTAINMENT INTEGRITY in accordance with the definition within 1 hour.

   b. Otherwise, be in HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2. The inside and outside isolation valves in the Containment Ventilation Purge System shall be locked, sealed, or otherwise secured closed whenever the Reactor Coolant System temperature exceeds 200°F.

3. The inside and outside isolation valves in the containment vacuum ejector suction line shall be locked, sealed, or otherwise secured closed whenever the Reactor Coolant System temperature exceeds 200°F.

B. Containment Airlocks

1. Each containment airlock shall be OPERABLE with both doors of the personnel airlock closed except when the airlock is being used for normal transit entry and exit through the containment, then at least one airlock door shall be closed.

   a. With one airlock or associated interlock inoperable, maintain the OPERABLE door closed and either restore the inoperable door to OPERABLE status or lock closed the OPERABLE door within 24 hours.

   b. If the personnel airlock inner door or interlock is inoperable, the outer personnel airlock door may be opened for repair and retest of the inner door. If the inoperability is due to the personnel airlock inner door seal exceeding the leakage test acceptance criteria, the outer personnel airlock door may be opened for a period of time not to exceed fifteen minutes with an annual cumulative time not to exceed one hour per year for repair and retest of the inner door seal.

   c. Otherwise, be in HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

C. Containment Isolation Valves

1. Containment isolation valves shall be OPERABLE.† 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

† Non-automatic or deactivated automatic containment isolation valves may be opened on an intermittent basis under administrative control. The valves identified in TS 3.8.A.2 and TS 3.8.A.3 are excluded from this provision.

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

d. Otherwise, place the unit in HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

D. Internal Pressure

1. Containment air partial pressure shall be maintained within the acceptable operation range as identified in Figure 3.8-1 whenever the Reactor Coolant System temperature and pressure exceed 350°F and 450 psig, respectively.

   a. With the containment air partial pressure outside the acceptable operation range, restore the air partial pressure to within acceptable limits within 1 hour or be in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

Basis

CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment will be restricted to those leakage paths and associated leak rates assumed in the accident analysis. These restrictions, in conjunction with the allowed leakage, will limit the site boundary radiation dose to the applicable limits of 10 CFR 50.67 or Regulatory Guide 1.183 during accident conditions.

The operability of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. The opening of manual or deactivated automatic containment isolation valves on an intermittent basis under administrative control includes the following considerations: (1) stationing an operator, who is in constant communication with the control room, at the valve controls, (2) instructing this operator to close these valves in an accident situation, and

(3) assuring that environmental conditions will not preclude access to close the valves and 4) that this administrative or manual action will prevent the release of radioactivity outside the containment.

The Reactor Coolant System temperature and pressure being below 350°F and 450 psig, respectively, ensures that no significant amount of flashing steam will be formed and hence that there would be no significant pressure buildup in the containment if there is a loss-of-coolant accident. Therefore, the containment internal pressure is not required to be subatmospheric prior to exceeding 350°F and 450 psig.

The allowable value for the containment air partial pressure is presented in TS Figure 3.8-1 for service water temperatures from 25 to 100°F. The RWST water shall have a maximum temperature of 45°F.

The horizontal upper limit line in TS Figure 3.8-1 is based on MSLB peak calculated pressure criteria, and the sloped line from 70°F to 100°F service water temperatures is based on LOCA depressurization criteria.

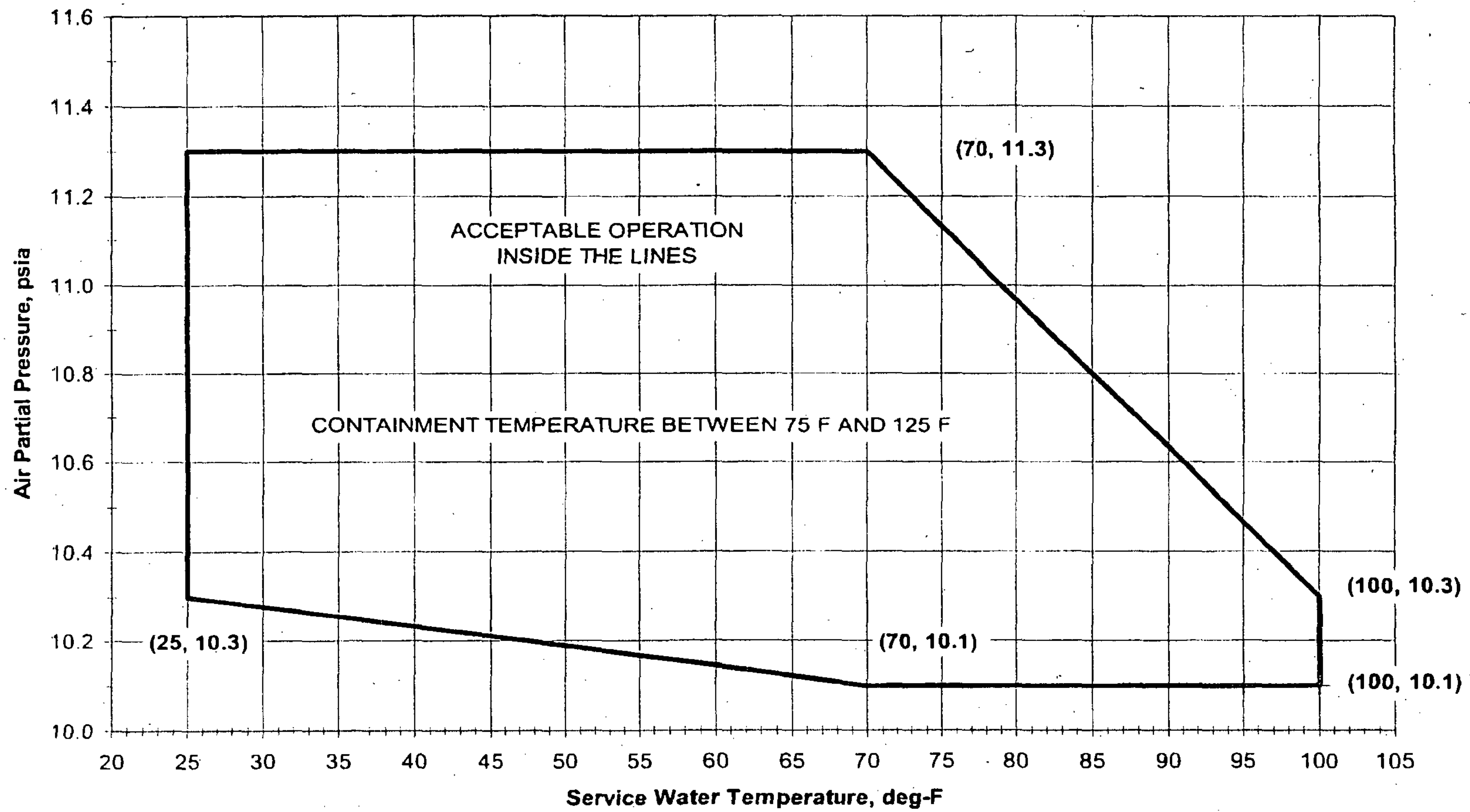
If the containment air partial pressure rises to a point above the allowable value the reactor shall be brought to the HOT SHUTDOWN condition. If a LOCA occurs at the time the containment air partial pressure is at the maximum allowable value, the maximum containment pressure will be less than design pressure (45 psig), the containment will depressurize to 1.0 psig within 1 hour and less than 0.0 psig within 4 hours. The radiological consequences analysis demonstrates acceptable results provided the containment pressure does not exceed 1.0 psig for the interval from 1 to 4 hours following the Design Basis Accident.

If the containment air partial pressure cannot be maintained greater than or equal to the minimum pressure in Figure 3.8-1, the reactor shall be brought to the HOT SHUTDOWN condition. The shell and dome plate liner of the containment are capable of withstanding an internal pressure as low as 3 psia, and the bottom mat liner is capable of withstanding an internal pressure as low as 8 psia.

<u>References</u>

UFSAR Section 4.2.2.4	Reactor Coolant Pump
UFSAR Section 5.2	Containment Isolation
UFSAR Section 5.2.1	Design Bases
UFSAR Section 5.2.2	Isolation Design
UFSAR Section 5.3.4	Containment Vacuum System

SURRY TECHNICAL SPECIFICATION CURVE FOR CONTAINMENT
ALLOWABLE AIR PARTIAL PRESSURE INDICATION VS. SERVICE WATER TEMPERATURE



Note: Operation on or outside the line requires entry into TS 3.8.D.1.a

3.9 STATION SERVICE SYSTEMS

Applicability

Applies to availability of electrical power for operation of station auxiliaries.

Objective

To define those conditions of electrical power availability necessary to provide for safe reactor operation.

Specification

A. A unit's reactor shall not be made critical without:

1. All three of the unit's 4,160V buses energized

2. All six of the unit's 480V buses energized

3. Both of the 125 V DC buses energized as explained in Section 3.16

4. One battery charger per battery operating as explained in Section 3.16

5. Both of the 4,160V emergency buses energized as explained in Section 3.16

6. All four of the 480V emergency buses energized as explained in Section 3.16

7. Two emergency diesel generators OPERABLE as explained in Section 3.16.

B. The requirements of Specification 3.9-A items 3, 4, 5, 6, and 7 may be modified as provided in Section 3.16-B.

Basis

During startup of a unit, the station's 4,160V and 480V normal and emergency buses are energized from the station's 34.5KV buses. At reactor power levels greater than 5 percent of rated power the 34.5KV buses are required to energize only the emergency buses because at this power level the station generator can supply sufficient power to the normal 4,160V and 480V lines to operate the unit. Three reactor coolant loop operation with all 4,160V and 480V buses energized is the normal mode of operation for a unit.

The electrical power requirements and the emergency power testing requirements for the auxiliary feedwater cross-connect are contained in TS 3.6.C.4.c and TS 4.6, respectively.

References

FSAR Section 8.4 Station Service Systems

FSAR Section 8.5 Emergency Power Systems

3.10 REFUELING

Applicability

Applies to operating limitations during REFUELING OPERATIONS or irradiated fuel movement in the Fuel Building.

Objective

To assure that no accident could occur during REFUELING OPERATIONS or irradiated fuel movement in the Fuel Building that would affect public health and safety.

Specification

A. During REFUELING OPERATIONS the following conditions are satisfied:

   1. The equipment access hatch and at least one door in the personnel airlock shall be capable of being closed. For those penetrations which provide a direct path from containment atmosphere to the outside atmosphere, the containment isolation valves shall be OPERABLE or the penetration shall be closed by a valve, blind flange, or equivalent or the penetration shall be capable of being closed.

2. At least one source range neutron detector shall be in service at all times when the reactor vessel head is unbolted. Whenever core geometry or coolant chemistry is being changed, subcritical neutron flux shall be continuously monitored by at least two source range neutron detectors, each with continuous visual indication in the Main Control Room and one with audible indication within the containment. During core fuel loading phases, there shall be a minimum neutron count rate detectable on two operating source range neutron detectors with the exception of initial core loading, at which time a minimum neutron count rate need be established only when there are eight (8) or more fuel assemblies loaded into the reactor vessel.

3. The manipulator crane area monitors and the containment particulate and gas monitors shall be OPERABLE and continuously monitored to identify the occurrence of a fuel handling accident.

4. At least one residual heat removal pump and heat exchanger shall be OPERABLE to circulate reactor coolant. The residual heat removal loop may be removed from operation for up to 1 hour per 8-hour period during the performance of core alterations or reactor vessel surveillance inspections.

5. Two residual heat removal pumps and heat exchangers shall be OPERABLE to circulate reactor coolant when the water level above the top of the reactor pressure vessel flange is less than 23 feet.

6. At least 23 feet of water shall be maintained over the top of the reactor pressure vessel flange during movement of fuel assemblies.

7. With the reactor vessel head unbolted or removed, any filled portions of the Reactor Coolant System and the refueling canal shall be maintained at a boron concentration which is:

   a. Sufficient to maintain K-effective equal to 0.95 or less, and

   b. Greater than or equal to 2300 ppm and shall be checked by sampling at least once every 72 hours.

8. Direct communication between the Main Control Room and the refueling cavity manipulator crane shall be available whenever changes in core geometry are taking place.

9. No movement of irradiated fuel in the reactor core shall be accomplished until the reactor has been subcritical for a period of at least 100 hours.

10. A spent fuel cask or heavy loads exceeding 110 percent of the weight of a fuel assembly (not including fuel handling tool) shall not be moved over spent fuel, and only one spent fuel assembly will be handled at one time over the reactor or the spent fuel pit.

    This restriction does not apply to the movement of the transfer canal door.

11. Two Main Control Room/Emergency Switchgear Room (MCR/ESGR) Emergency Ventilation System (EVS) trains shall be OPERABLE.

    a. With one required train inoperable for reasons other than an inoperable MCR/ESGR envelope boundary, restore the inoperable train to OPERABLE status within 7 days. If the inoperable train is not returned to OPERABLE status within 7 days, comply with Specification 3.10.C.

    b. If two required trains are inoperable or one or more required trains are inoperable due to an inoperable MCR/ESGR envelope boundary, comply with Specification 3.10.C.

12. Manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation shall be OPERABLE as specified in TS 3.7.F.

13. Three chillers shall be OPERABLE in accordance with the power supply requirements of Specification 3.23.A. With one of the required OPERABLE chillers inoperable or not powered as required by Specification 3.23.A.1, return the inoperable chiller to OPERABLE status within 7 days or comply with Specification 3.10.C. With two of the required OPERABLE chillers inoperable or not powered as required by Specification 3.23.A.1, comply with Specification 3.10.C.

14. Eight air handling units (AHUs) shall be OPERABLE in accordance with the operability requirements of Specification 3.23.A. With two AHUs inoperable on the shutdown unit, ensure that one AHU is OPERABLE in each unit's main control room and emergency switchgear room, and restore an inoperable AHU to OPERABLE status within 7 days, or comply with Specification 3.10.C. With more than two AHUs inoperable, comply with Specification 3.10.C.

B. During irradiated fuel movement in the Fuel Building the following conditions are satisfied:

1. The fuel pit bridge area monitor and the ventilation vent stack 2 particulate and gas monitors shall be OPERABLE and continuously monitored to identify the occurrence of a fuel handling accident.

2. A spent fuel cask or heavy loads exceeding 110 percent of the weight of a fuel assembly (not including fuel handling tool) shall not be moved over spent fuel, and only one spent fuel assembly will be handled at one time over the reactor or the spent fuel pit.

   This restriction does not apply to the movement of the transfer canal door.

3. A spent fuel cask shall not be moved into the Fuel Building unless the Cask Impact Pads are in place on the bottom of the spent fuel pool.

4. Two MCR/ESGR EVS trains shall be OPERABLE.

   a. With one required train inoperable for reasons other than an inoperable MCR/ESGR envelope boundary, restore the inoperable train to OPERABLE status within 7 days. If the inoperable train is not returned to OPERABLE status within 7 days, comply with Specification 3.10.C.

   b. If two required trains are inoperable or one or more required trains are inoperable due to an inoperable MCR/ESGR envelope boundary, comply with Specification 3.10.C.

5. Manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation shall be OPERABLE as specified in TS 3.7.F.

6. Three chillers shall be OPERABLE in accordance with the power supply requirements of Specification 3.23.A. With one of the required OPERABLE chillers inoperable or not powered as required by Specification 3.23.A.1, return the inoperable chiller to OPERABLE status within 7 days or comply with Specification 3.10.C. With two of the required OPERABLE chillers inoperable or not powered as required by Specification 3.23.A.1, comply with Specification 3.10.C.

7. Eight air handling units (AHUs) shall be OPERABLE in accordance with the operability requirements of Specification 3.23.A. With two AHUs inoperable on either unit, ensure that one AHU is OPERABLE in each unit's main control room and emergency switchgear room, and restore an inoperable AHU to OPERABLE status within 7 days, or comply with Specification 3.10.C. With more than two AHUs inoperable on a unit, comply with Specification 3.10.C.

C. If any one of the specified limiting conditions for refueling is not met, REFUELING OPERATIONS or irradiated fuel movement in the Fuel Building shall cease and irradiated fuel shall be placed in a safe position, work shall be initiated to correct the conditions so that the specified limit is met, and no operations which increase the reactivity of the core shall be made.

D. After initial fuel loading and after each core refueling operation and prior to reactor operation at greater than 75% of rated power, the movable incore detector system shall be utilized to verify proper power distribution.

E. The requirements of 3.0.1 are not applicable.

Basis

Detailed instructions, the above specified precautions, and the design of the fuel handling equipment, which incorporates built-in interlocks and safety features, provide assurance that an accident, which would result in a hazard to public health and safety, will not occur during unit REFUELING OPERATIONS or irradiated fuel movement in the Fuel Building. When no change is being made in core geometry, one neutron detector is sufficient to monitor the core and permits maintenance of the out-of-function instrumentation. Continuous monitoring of radiation levels and neutron flux provides immediate indication of an unsafe condition.

Potential escape paths for fission product radioactivity within containment are required to be closed or capable of closure to prevent the release to the environment. However, since there is no potential for significant containment pressurization during refueling, the Appendix J leakage criteria and tests are not applicable.

The containment equipment access hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of the containment. During REFUELING OPERATIONS, the equipment hatch must be capable of being closed.

The containment airlocks, which are also part of the containment pressure boundary, provide a means for personnel access during periods when CONTAINMENT INTEGRITY is required. Each airlock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors to remain open for extended periods when frequent containment entry is necessary. During REFUELING OPERATIONS, containment closure does not have to be maintained, but airlock doors may need to be closed to establish containment closure. Therefore, the door interlock mechanism may remain disabled, but one airlock door must be capable of being closed.

Containment penetrations that terminate in the Auxiliary Building or Safeguards and provide direct access from containment atmosphere to outside atmosphere must be isolated or capable of being closed by at least one barrier during REFUELING OPERATIONS. The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated by at least one barrier during REFUELING OPERATIONS. Isolation may be achieved by an OPERABLE isolation valve, a closed valve, a blind flange, or by an equivalent isolation method. Equivalent isolation methods must be evaluated and may include use of a material that can provide a temporary, atmospheric pressure ventilation barrier.

For the personnel airlock, equipment access hatch, and other penetrations, 'capable of being closed' means the openings are able to be closed; they do not have to be sealed or meet the leakage criteria of TS 4.4. Station procedures exist that ensure in the event of a fuel handling accident, that the open personnel airlock and other penetrations can and will be closed. Closure of the equipment hatch will be accomplished in accordance with station procedures and as allowed by dose rates in containment. The radiological analysis of the fuel handling accident does not take credit for closure of the personnel airlock, equipment access hatch or other penetrations.

The fuel building ventilation exhaust and containment ventilation purge exhaust may be diverted through charcoal filters whenever refueling is in progress. However, there is no requirement for filtration since the Fuel Handling Accident analysis takes no credit for these filters. At least one flow path is required for cooling and mixing the coolant contained in the reactor vessel so as to maintain a uniform boron concentration and to remove residual heat.

The requirements in this specification for the Main Control Room/Emergency Switchgear Room (MCR/ESGR) Emergency Ventilation System (EVS) and the MCR and ESGR Air Conditioning System (chillers and air handling units) apply to the shutdown unit. If any of the specified limiting conditions is not met, the requirements appropriately suspend activities that could result in a release of radioactivity that might require isolation of the MCR/ESGR envelope and place irradiated fuel in a safe position without delay and in a controlled manner. The requirements applicable to the operating unit are contained in Specifications 3.21 and 3.23.

During REFUELING OPERATIONS and during the movement of irradiated fuel assemblies, the MCR/ESGR EVS and the manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation must be OPERABLE to ensure that the MCR/ESGR envelope will remain habitable during and following a Design Basis Accident.

Specifically, during REFUELING OPERATIONS and during movement of irradiated fuel assemblies, the MCR/ESGR EVS and the manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation must be OPERABLE to respond to the release from a fuel handling accident.

<u>3.10.A.7 and 8</u>

During refueling, the reactor refueling water cavity is filled with approximately 220,000 gal of water borated to at least 2,300 ppm boron. The boron concentration of this water, established by Specification 3.10.A.7, is sufficient to maintain the reactor subcritical by at least 5% $\Delta k/k$ in the COLD SHUTDOWN condition with all control rod assemblies inserted. This includes a 1% $\Delta k/k$ and a 50 ppm boron concentration allowance for uncertainty. This concentration is also sufficient to maintain the core subcritical with no control rod assemblies inserted into the reactor. Checks are performed during the reload design and safety analysis process to ensure the K-effective is equal to or less than 0.95 for each core. Periodic checks of refueling water boron concentration assure the proper shutdown margin. Specification 3.10.A.8 allows the Control Room Operator to inform the manipulator operator of any impending unsafe condition detected from the main control board indicators during fuel movement.

3.10.A.11 and 12 and 3.10.B.4 and 5

When one MCR/ESGR EVS train is inoperable, for reasons other than an inoperable MCR/ESGR envelope boundary, action must be taken to restore OPERABLE status within 7 days. In this condition, the remaining required OPERABLE MCR/ESGR EVS train is adequate to perform the MCR/ESGR envelope occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE MCR/ESGR EVS train could result in loss of MCR/ESGR EVS function. The 7 day Allowed Outage Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

During REFUELING OPERATIONS or during movement of irradiated fuel assemblies, if the required inoperable MCR/ESGR EVS train cannot be restored to OPERABLE status within the required Allowed Outage Time, or two required MCR/ESGR EVS trains are inoperable or with one or more required MCR/ESGR EVS trains inoperable due to an inoperable MCR/ESGR envelope boundary, action must be taken to suspend activities that could result in a release of radioactivity that might require isolation of the MCR/ESGR envelope. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

In addition to the above safeguards, interlocks are used during refueling to assure safe handling of the fuel assemblies. An excess weight interlock is provided on the lifting hoist to prevent movement of more than one fuel assembly at a time. The spent fuel transfer mechanism can accommodate only one fuel assembly at a time.

Upon each completion of core loading and installation of the reactor vessel head, specific mechanical and electrical tests will be performed prior to initial criticality.

The fuel handling accident has been analyzed based on the methodology outlined in Regulatory Guide 1.183. The analysis assumes 100% release of the gap activity from the assembly with maximum gap activity after a 100-hour decay period following operation at 2605 MWt.

Detailed procedures and checks insure that fuel assemblies are loaded in the proper locations in the core. As an additional check, the movable incore detector system will be used to verify proper power distribution. This system is capable of revealing any assembly enrichment error or loading error which could cause power shapes to be peaked in excess of design value.

References

UFSAR Section 5.2	Containment Isolation
UFSAR Section 6.3	Consequence Limiting Safeguards
UFSAR Section 9.12	Fuel Handling System
UFSAR Section 9.13	Auxiliary Ventilation Systems
UFSAR Section 11.3	Radiation Protection
UFSAR Section 13.3	Table 13.3-1
UFSAR Section 14.4.1	Fuel Handling Accidents
FSAR Supplement:	Volume I: Question 3.2

3.11 RADIOACTIVE GAS STORAGE

Applicability

Applies to the storage of radioactive gases.

Objective

To establish conditions by which gaseous waste containing radioactive materials may be stored.

Specification

A. Explosive Gas Mixture

1. The concentration of oxygen in the waste gas holdup system shall be limited to less than or equal to 2% by volume whenever the hydrogen concentration could exceed 4% by volume.

   a. With the concentration of oxygen in the waste gas holdup system greater than 2% by volume but less than or equal to 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

   b. With the concentration of oxygen in the waste gas holdup system greater than 4% by volume, immediately suspend all additions of waste gases to the affected tank and reduce the concentration of oxygen to less than or equal to 4% by volume, then take the action in 1.a above.

   c. With the requirements of action 1.a above not satisfied, immediately suspend all additions of waste gases to the affected tank until the oxygen concentration is restored to less than or equal to 2% by volume, and submit a special report to the Commission within the next 30 days outlining the following:

      (1) The cause of the waste gas decay tank exceeding the 2% oxygen limit.

      (2) The reason why the oxygen concentration could not be returned to within limits.

(3) The actions taken and the time required to return the oxygen concentration to within limits.

2. The requirements of Specification 3.0.1 are not applicable.

B. Gas Storage Tanks

1. The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 24,600 curies of noble gases (considered as Xe-133).
2. With the quantity of radioactive material in any gas storage tank exceeding the above limit, immediately suspend all addition of radioactive material to the tank and within 48 hours reduce the tank contents to within the limits.
3. The requirements of Specification 3.0.1 are not applicable.

Basis

Explosive Gas Mixture

Specification 3.11.A is provided to ensure that the concentration of potentially explosive gas mixtures contained in the waste gas holdup system is maintained below the flammability limits of hydrogen and oxygen. Maintaining oxygen below the concentration that will support combustion at any concentration of hydrogen provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR 50.

Gas Storage Tanks

The tanks included in Specification 3.11.B are those tanks for which the quantity of radioactivity contained is not limited directly or indirectly by another Technical Specification to a quantity that is less than the quantity which provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting total body exposure to an individual at the nearest exclusion area boundary will not exceed 0.5 rem in an event of 2 hours.

Restricting the quantity of radioactivity contained in each gas storage tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting total body exposure to an individual at the nearest exclusion area boundary will not exceed 0.5 rem. This is consistent with Branch Technical Position ETSB 11-5 in NUREG-0800, July 1981.

3.12 CONTROL ROD ASSEMBLIES AND POWER DISTRIBUTION LIMITS

Applicability

Applies to the operation of the control rod assemblies and power distribution limits.

Objective

To ensure core subcriticality after a reactor trip, a limit on potential reactivity insertions from hypothetical control rod assembly ejection, and an acceptable core power distribution during power operation.

Specification

A. Control Bank Insertion Limits

1. Whenever the reactor is critical, except for physics tests and control rod assembly surveillance testing, each shutdown bank shall be within the insertion limits specified in the CORE OPERATING LIMITS REPORT. With one or more shutdown banks not within limits:

   a. Within 1 hour, verify shutdown margin is within the limits specified in the CORE OPERATING LIMITS REPORT or initiate boration to restore shutdown margin to within limit and

   b. Within 2 hours, restore shutdown banks to within limits.

   If the above requirements are not met, be in HOT SHUTDOWN within 6 hours.

2. Whenever the reactor is critical, except for physics tests and control rod assembly surveillance testing, the full length control banks shall be within the insertion limits specified in the CORE OPERATING LIMITS REPORT. With control bank insertion limits not met:

   a. Within 1 hour, verify shutdown margin is within the limits specified in the CORE OPERATING LIMITS REPORT or initiate boration to restore shutdown margin to within limit and

b. Within 2 hours, restore control banks to within limits.

If the above requirements are not met, be in HOT SHUTDOWN within 6 hours.

3. The Control Bank Insertion Limits shown in the CORE OPERATING LIMITS REPORT may be revised on the basis of physics calculations and physics data obtained during unit startup and subsequent operation, in accordance with the following:

a. The sequence of withdrawal of the control banks, when going from zero to 100% power, is A, B, C, D.

b. An overlap of control banks, consistent with physics calculations and physics data obtained during unit startup and subsequent operation, will be permitted.

c. The shutdown margin with allowance for a stuck control rod assembly shall be within the limits specified in the CORE OPERATING LIMITS REPORT under all steady-state operation conditions, except for physics tests, from zero to full power, including effects of axial power distribution. The shutdown margin as used here is defined as the amount by which the reactor core would be subcritical at HOT SHUTDOWN ($T_{avg} \geq 547°F$) if all control rod assemblies were tripped, assuming that the highest worth control rod assembly remained fully withdrawn, and assuming no changes in xenon or boron.

4. Whenever the reactor is subcritical, except for physics tests, the critical control rod assembly position, i.e., the control rod assembly position at which criticality would be achieved if the control rod assemblies were withdrawn in normal sequence with no other reactivity changes, shall not be lower than the insertion limit for zero power.

5. Insertion limits do not apply during physics tests or during periodic surveillance testing of control rod assemblies. However, the shutdown margin indicated above must be maintained except for the LOW POWER PHYSICS TEST to measure control and shutdown bank worth and shutdown margin. For this test the reactor may be critical with all but one full length control rod assembly, expected to have the highest worth, inserted.

6. With a maximum of one control or shutdown bank inserted beyond the insertion limit specified in Specification 3.12.A.2 during control rod assembly testing pursuant to Specification 4.1, and immovable due to a failure of the Rod Control System, POWER OPERATION

may continue* provided that:

a. the affected bank insertion is limited to 18 steps below the insertion limit as measured by the group step counter demand position indicators,

b. the affected bank is trippable,

c. each control rod assembly is aligned to within ± 12 steps of its respective group step counter demand position indicator,

d. The shutdown margin requirement of Specification 3.12.A.3.c is determined to be met at least every 12 hours thereafter, and

e. the affected bank is restored to within the insertion limits of Specification 3.12.A within 72 hours.

Otherwise place the unit in HOT SHUTDOWN within the next 6 hours.

B. Power Distribution Limits

1. At all times except during LOW POWER PHYSICS TESTS, the hot channel factors defined in the basis meet the following limits:

$F_Q(Z) \leq (CFQ/P) \times K(Z)$ for $P > 0.5$
$F_Q(Z) \leq (CFQ/0.5) \times K(Z)$ for $P \leq 0.5$

where: CFQ = the FQ limit at RATED POWER specified in the CORE OPERATING LIMITS REPORT,

$$P = \frac{\text{THERMAL POWER}}{\text{RATED POWER}}, \text{ and}$$

K(Z) = the normalized FQ limit as a function of core height, Z, as specified in the CORE OPERATING LIMITS REPORT

$F\Delta H(N) \leq CFDH \times (1 + PFDH \times (1-P))$

where: CFDH = the FΔH(N) limit at RATED POWER specified in the CORE OPERATING LIMITS REPORT,

PFDH = the Power Factor Multiplier for FΔH(N) specified in the CORE OPERATING LIMITS REPORT, and

$$P = \frac{\text{THERMAL POWER}}{\text{RATED POWER}}$$

* Provision for continued operation does not apply to Control Bank D inserted beyond the insertion limit.

2. Prior to exceeding 75% of RATED POWER following each core loading and during each effective full power month of operation thereafter, power distribution maps using the movable detector system shall be made to confirm that the hot channel factor limits of this specification are satisfied. For the purpose of this confirmation:

   a. The measurement of total peaking factor F_Q^{Meas} shall be increased by eight percent to account for manufacturing tolerances, measurement error and the effects of rod bow. The measurement of enthalpy rise hot channel factor $F_{\Delta H}^N$ shall be compared directly to the limit specified in Specification 3.12.B.1. If any measured hot channel factor exceeds its limit specified under Specification 3.12.B.1, the reactor power and high neutron flux trip setpoint shall be reduced until the limits under Specification 3.12.B.1 are met. If the hot channel factors cannot be brought to within the FQ(Z) and $F_{\Delta H}^N$ limits as specified in the CORE OPERATING LIMITS REPORT within 24 hours, the Overpower ΔT and Overtemperature ΔT trip setpoints shall be similarly reduced within the next 4 hours.

   b. The provisions of Specification 4.0.4 are not applicable.

3. The reference equilibrium indicated axial flux difference (called the target flux difference) at a given power level P_O is that indicated axial flux difference with the core in equilibrium xenon conditions (small or no oscillation) and the control rod assemblies more than 190 steps withdrawn. The target flux difference at any other power level P is equal to the target value at P_O multiplied by the ratio P/P_O. The target flux difference shall be measured at least once per equivalent full power quarter. The target flux difference must be updated during each effective full power month of operation either by actual measurements or by linear interpolation using the most recent value and the value predicted for the end of the cycle life. The provisions of Specification 4.0.4 are not applicable.

4. Except as modified by Specifications 3.12.B.4.a, b, c, or d below, the indicated axial flux difference shall be maintained within a ± 5% band about the target flux difference (defines the target band on axial flux difference).

a. At a power level greater than 90 percent of RATED POWER, if the indicated axial flux difference deviates from its target band, within 15 minutes either restore the indicated axial flux difference to within the target band or reduce the reactor power to less than 90 percent of RATED POWER.

b. At a power level less than or equal to 90 percent of RATED POWER,

(1) The indicated axial flux difference may deviate from its target band for a maximum of one hour (cumulative) in any 24-hour period provided the flux difference is within the limits shown on TS Figure 3.12-3. One minute penalty is accumulated for each one minute of operation outside of the target band at power levels equal to or above 50% of RATED POWER.

(2) If Specification 3.12.B.4.b.(1) is violated, then the reactor power shall be reduced to less than 50% power within 30 minutes and the high neutron flux setpoint shall be reduced to less than or equal to 55% power within the next four hours.

(3) A power increase to a level greater than 90 percent of RATED POWER is contingent upon the indicated axial flux difference being within its target band.

(4) Surveillance testing of the Power Range Neutron Flux Channels may be performed pursuant to TS Table 4.1-1 provided the indicated axial flux difference is maintained within the limits of TS Figure 3.12-3. A total of 16 hours of operation may be accumulated with the axial flux difference outside of the target band during this testing without penalty deviation.

c. At a power level less than or equal to 50 percent of RATED POWER,

(1) The indicated axial flux difference may deviate from its target band.

(2) A power increase to a level greater than 50 percent of RATED POWER is contingent upon the indicated axial flux difference not being outside its target band for more than one hour accumulated penalty during the preceding 24-hour period. One half minute penalty is accumulated for each one minute of operation outside of the target band at power levels between 15% and 50% of RATED POWER.

d. The axial flux difference limits for Specifications 3.12.B.4.a, b, and c may be suspended during the performance of physics tests provided:

(1) The power level is maintained less than or equal to 85% of RATED POWER, and

(2) The limits of Specification 3.12.B.1 are maintained. The power level shall be determined to be less than or equal to 85% of RATED POWER at least once per hour during physics tests. Verification that the limits of Specification 3.12.B.1 are being met shall be demonstrated through in-core flux mapping at least once per 12 hours.

Alarms shall normally be used to indicate the deviations from the axial flux difference requirements in Specification 3.12.B.4.a and the flux difference time limits in Specifications 3.12.B.4.b and c. If the alarms are out of service temporarily, the axial flux difference shall be logged and conformance to the limits assessed every hour for the first 24 hours and half-hourly thereafter. The indicated axial flux difference for each excore channel shall be monitored at least once per 7 days when the alarm is OPERABLE and at least once per hour for the first 24 hours after restoring the alarm to OPERABLE status.

5. The allowable QUADRANT POWER TILT is 2.0% and is only applicable while operating at THERMAL POWER > 50%.

6. If, except for operation at THERMAL POWER < 50% or for physics and control rod assembly surveillance testing, the QUADRANT POWER TILT exceeds 2%, then:

   a. Within 2 hours, either the hot channel factors shall be determined and the power level adjusted to meet the requirement of Specification 3.12.B.1, or

   b. The power level shall be reduced from RATED POWER 2% for each percent of QUADRANT POWER TILT. The high neutron flux trip setpoint shall be similarly reduced within the following 4 hours.

   c. If the QUADRANT POWER TILT exceeds 10%, the power level shall be reduced from RATED POWER 2% for each percent of QUADRANT POWER TILT within the next 30 minutes. The high neutron flux trip setpoint shall be similarly reduced within the following 4 hours.

7. If, except for operation at THERMAL POWER < 50% or for physics and control rod assembly surveillance testing, after a further period of 24 hours, the QUADRANT POWER TILT in Specification 3.12.B.5 above is not corrected to less than 2%:

   a. If the design hot channel factors for RATED POWER are not exceeded, an evaluation as to the cause of the discrepancy shall be made and a special report issued to the Nuclear Regulatory Commission.

   b. If the design hot channel factors for RATED POWER are exceeded and the power is greater than 10%, then the high neutron flux, Overpower ΔT and Overtemperature ΔT trip setpoints shall be reduced 1% for each percent the hot channel factor exceeds the RATED POWER design values within the next 4 hours, and the Nuclear Regulatory Commission shall be notified.

c. If the hot channel factors are not determined, then the Overpower DT and Overtemperature ΔT trip setpoints shall be reduced by the equivalent of 2% power for every 1% QUADRANT POWER TILT within the next 4 hours, and the Nuclear Regulatory Commission shall be notified.

C. Control Rod Assemblies

1. To be considered OPERABLE during startup and POWER OPERATION each control rod assembly shall:

   1) be trippable,

   2) aligned within ± 12 steps or ± 24 steps of its group step demand position, as defined in Section 3.12.E.1.b, and

   3) have a drop time of less than or equal to 2.4 seconds to dashpot entry.

2. To be considered OPERABLE during shutdown modes, each control rod assembly shall:

   1) be trippable, and

   2) have a drop time of less than or equal to 2.4 seconds to dashpot entry.

3. Startup and POWER OPERATION may continue with one control rod assembly inoperable provided that within one hour either:

   a. The control rod assembly is restored to OPERABLE status, as defined in Specification 3.12.C.1 and 2, or

   b. the shutdown margin requirement of Specification 3.12.A.3.c is satisfied. POWER OPERATION may then continue provided that:

      1) either:

(a) power shall be reduced to less than 75% of RATED POWER within one (1) hour, and the High Neutron Flux trip setpoint shall be reduced to less than or equal to 85% of RATED POWER within the next four (4) hours, or

(b) the remainder of the control rod assemblies in the group with the inoperable control rod assembly are aligned to within 12 steps of the inoperable rod within one (1) hour while maintaining the control rod assembly sequence and insertion limits specified in the CORE OPERATING LIMITS REPORT; the THERMAL POWER level shall be restricted pursuant to Specification 3.12.A during subsequent operation.

2) the shutdown margin requirement of Specification 3.12.A.3.c is determined to be met within one hour and at least once per 12 hours thereafter.

3) the hot channel factors are shown to be within the design limits of Specification 3.12.B.1 within 72 hours. Further, it shall be demonstrated that the value of $F_{xy}(Z)$ used in the Constant Axial Offset Control analysis is still valid.

4) a reevaluation of each accident analysis of Table 3.12-1 is performed within 5 days. This reevaluation shall confirm that the previous analyzed results of these accidents remain valid for the duration of operation under these conditions.

5) If power has been reduced in accordance with Specification 3.12.C.3.b, power may be increased above 75% of RATED POWER provided that:

   (a) an analysis has been performed to determine the hot channel factors and the resulting allowable power level based on the limits of Specification 3.12.B.1, and

   (b) an evaluation of the effects of operating at the increased power level on the accident analyses of Table 3.12-1 has been completed.

4. With more than one inoperable control rod assembly, as defined in Specification 3.12.C.1, determine within 1 hour that the shutdown margin requirement of Specification 3.12.A.3.c is satisfied and be in HOT SHUTDOWN within 6 hours.

5. The provisions of Specifications 3.12.C.1 and 3.12.C.4 shall not apply during LOW POWER PHYSICS TESTS in which the control rod assemblies are intentionally misaligned.

D. QUADRANT POWER TILT

1. If the reactor is operating above 75% of RATED POWER with one excore nuclear channel out of service, the QUADRANT POWER TILT shall be determined:
   a. Once per day, and
   b. After a change in power level greater than 10% or more than 30 inches of control rod motion.

2. The QUADRANT POWER TILT shall be determined by one of the following methods:
   a. Movable detectors (at least two per quadrant)
   b. Core exit thermocouples (at least four per quadrant)

E. Rod Position Indication System and Bank Demand Position Indication System

1. From movement of control banks to achieve criticality and with the REACTOR CRITICAL, rod position indication shall be provided as follows:

    a. Above 50% power, the Rod Position Indication System shall be OPERABLE and capable of determining the control rod assembly positions to within ± 12 steps of their respective group step demand counter indications.

    b. From movement of control banks to achieve criticality up to 50% power, the Rod Position Indication System shall be OPERABLE and capable of determining the control rod assembly positions to within ± 24 steps of their respective group step demand counter indications for a maximum of one hour out of twenty-four, and to within ± 12 steps otherwise.

    c. From movement of control banks to achieve criticality and with the REACTOR CRITICAL, the Bank Demand Position Indication System shall be OPERABLE and capable of determining the group demand positions to within ± 2 steps.

2. If one rod position indicator per group for one or more groups is inoperable, the following action a or b or c shall be taken:

    a. The position of the control rod assembly shall be verified indirectly using the movable incore detectors at least once per 8 hours, or

    b. The following indirect verification of control rod assembly position shall be performed using the movable incore detectors:

        (1) Within 8 hours of the rod position indicator inoperability, and

        (2) Once every 31 effective full power days thereafter, and

        (3) Within 8 hours after each unintended rod movement, and

        (4) Within 8 hours after each rod movement greater than 12 steps, and

(5) Prior to exceeding 50% RATED POWER if power is reduced below 50% RATED POWER, and

(6) Within 8 hours after reaching RATED POWER, or

c. Reduce power to less than 50% of RATED POWER within 8 hours. During operations below 50% of RATED POWER, no special monitoring is required.

3. If more than one rod position indicator per group is inoperable, place the control rods under manual control immediately, monitor and record RCS T_{avg} once per hour, verify the position of the control rod assemblies indirectly using the movable incore detectors at least once per 8 hours, and restore inoperable position indicators to OPERABLE status such that a maximum of one position indicator per group is inoperable within 24 hours.

4. If one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position, verify the position of the control rod assemblies indirectly using the movable incore detectors within 4 hours or reduce power to less than 50% of RATED POWER within 8 hours.

5. If one group step demand counter per bank for one or more banks is inoperable, verify that all rod position indicators for the affected bank(s) are OPERABLE once per 8 hours and verify that the most withdrawn rod and the least withdrawn rod of the affected bank(s) are less than or equal to 12 steps apart once per 8 hours. Alternatively, reduce power to less than 50% of RATED POWER within 8 hours.

6. If the requirements of Specification 3.12.E.2, 3.12.E.3, 3.12.E.4, or 3.12.E.5 are not satisfied, then the unit shall be placed in HOT SHUTDOWN within 6 hours.

F. DNB Parameters

1. The following DNB related parameters shall be maintained within their limits during POWER OPERATION:

   - Reactor Coolant System $T_{avg} \leq$ the limit specified in the CORE OPERATING LIMITS REPORT
   - Pressurizer Pressure $\geq$ the limit specified in the CORE OPERATING LIMITS REPORT
   - Reactor Coolant System Total Flow Rate $\geq$ 273,000 gpm and $\geq$ the limit specified in the CORE OPERATING LIMITS REPORT

a. The Reactor Coolant System T_{avg}, Pressurizer Pressure, and Reactor Coolant System Total Flow Rate shall be verified to be within their limits at least once every 12 hours.

b. The Reactor Coolant System Total Flow Rate shall be determined to be within its limit by precision heat balance with the frequency specified in TS Table 4.1-2A.

2. When any of the parameters in Specification 3.12.F.1 has been determined to exceed its limit, either restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED POWER within the next 6 hours.

3. The limit for Pressurizer Pressure in Specification 3.12.F.1 is not applicable during either a THERMAL POWER ramp increase in excess of 5% of RATED POWER per minute or a THERMAL POWER step increase in excess of 10% of RATED POWER.

G. Shutdown Margin

1. Whenever the reactor is subcritical, the shutdown margin shall be within the limits specified in the CORE OPERATING LIMITS REPORT. If the shutdown margin is not within limits, within 15 minutes, initiate boration to restore shutdown margin to within limits.

Basis

The reactivity control concept assumed for operation is that reactivity changes accompanying changes in reactor power are compensated by control rod assembly motion. Reactivity changes associated with xenon, samarium, fuel depletion, and large changes in reactor coolant temperature (operating temperature to COLD SHUTDOWN) are compensated for by changes in the soluble boron concentration. During POWER OPERATION, the shutdown control rod assemblies are fully withdrawn and control of power is by the control banks. A reactor trip occurring during POWER OPERATION will place the reactor into HOT SHUTDOWN. The control rod assembly insertion limits provide for achieving HOT SHUTDOWN by reactor trip at any time, assuming the highest worth control rod assembly remains fully withdrawn, with sufficient margins to meet the assumptions used in the accident analysis. In addition, they provide a limit on the maximum inserted control rod assembly worth in the unlikely event of a hypothetical assembly ejection and provide for acceptable nuclear peaking factors. The limit may be determined on the basis of unit startup and operating data to provide a more realistic limit which will allow for more flexibility in unit operation and still assure compliance with the shutdown requirement.

The maximum shutdown margin requirement occurs at end of core life and is based on the value used in the analyses of the hypothetical steam break accident. The control rod assembly insertion limits are based on end of core life conditions. The shutdown margin for the entire cycle length shall be within the limits specified in the CORE OPERATING LIMITS REPORT. Other accident analyses with the exception of the Chemical and Volume Control System malfunction analyses are based on 1% reactivity shutdown margin. Relative positions of control banks are determined by a specified control bank overlap. This overlap is based on the consideration of axial power shape control. The specified control rod assembly insertion limits have been established to limit the potential ejected control rod assembly worth in order to account for the effects of fuel densification. The various control rod assemblies (shutdown banks, control banks A, B, C, and D) are each to be moved as a bank; that is, with each assembly in the bank within one step (5/8 inch) of the bank position.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called the group step demand counters) and the Rod Position Indication System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one group step demand counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step demand counter for that group. The Bank Demand Position Indication System is considered highly precise (± 2 steps).

The Rod Position Indication System provides an accurate indication of actual rod position, but at a lower precision than the group step demand counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube. The Rod Position Indication System is capable of monitoring rod position within at least ± 12 steps during steady state temperature conditions and within ± 24 steps during transient temperature conditions. Below 50% RATED POWER, a wider tolerance on indicated rod position for a maximum of one hour in every 24 hours is permitted to allow the system to reach thermal equilibrium. This thermal soak time is available both for a continuous one hour period or several discrete intervals as long as the total time does not exceed 1 hour in any 24 hour period and the indicated rod position does not exceed 24 steps from the group step demand counter position.

When a rod position indicator fails, the position of the rod can be verified by use of the movable incore detectors once every 8 hours (TS 3.12.E.2.a). TS 3.12.E.2.b allows an alternate method of monitoring control rod position using the movable incore detector system on a less frequent periodicity (i.e., initial position verification within 8 hours and every 31 effective full power days (EFPDs) thereafter) and with additional verification performed following circumstances in which rod position may have changed or after significant changes in power level have occurred. One of these circumstances is unintended rod movement, which is defined as the release of a rod's stationary gripper when no action was demanded either manually or automatically from the rod control system. Verification that no unintended rod movement occurred is performed by monitoring the rod control system stationary gripper coil current for indications of rod movement. The 31 EFPDs verification frequency minimizes excessive use of and increased wear on the movable incore monitoring system and accommodates concurrent performance with the existing TS 4.10 surveillance requirement for determination of hot channel factors. TS 3.12.E.2.c provides the alternative of reducing power to less than 50% of RATED POWER within 8 hours.

The requirements on the rod position indicators and the group step demand counters are only applicable from the movement of control banks to achieve criticality and with the REACTOR CRITICAL, because these are the only conditions in which the rods can affect core power distribution and in which the rods are relied upon to provide required shutdown margin. The various action statement time requirements are based on operating experience and reflect the significance of the circumstances with respect to verification of rod position and potential rod misalignment. Reduction of RATED POWER to less than or equal to 50% puts the core into a condition where rod position is not significantly affecting core peaking factors. Therefore, during operation below 50% RATED POWER, no special monitoring is required. In the shutdown conditions, the operability of the shutdown banks and control banks has the potential to affect the required shutdown margin, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

The specified control rod assembly drop time is consistent with safety analyses that have been performed.

An inoperable control rod assembly imposes additional demands on the operators. The permissible number of inoperable control rod assemblies is limited to one in order to limit the magnitude of the operating burden, but such a failure would not prevent dropping of the OPERABLE control rod assemblies upon reactor trip.

In the event that a failure of the Rod Control System renders control rod assemblies immovable, provision is made for continued operation provided:

- the affected control rod assemblies remain trippable,
- the individual control rod assembly alignment limits are met.

In the event that a failure of the Rod Control System renders control rod assembly banks immovable during control rod assembly surveillance testing, provision is made for 72 hours of continued operation provided:

- the affected control rod assemblies remain trippable,
- the individual control rod assembly alignment limits are met,
- a maximum of one control or shutdown bank is inserted no more than 18 steps below the insertion limit, and
- the shutdown margin requirements are verified every 12 hours during the period the insertion limit is not met.

The 72 hour provision does not apply to Control Bank D since insertion of D bank below the insertion limit is not required for control rod assembly surveillance testing.

Checks are performed for each reload core to ensure that this minor bank insertion will not result in power distributions which violate the Departure from Nucleate Boiling (DNB) criterion for ANS Condition II transient (moderate frequency transients analyzed in Section 14.2 of the UFSAR) during the repair period or in a violation of the shutdown margin requirements of Specification of 3.12.A.3.c during the repair period.

The 72 hour period for a control rod assembly bank to be inserted below its limit restricts the likelihood of a more severe (i.e., ANS Condition III or IV) accident or transient condition.

Two criteria have been chosen as a design basis for fuel performance related to fission gas release, pellet temperature, and cladding mechanical properties. First, the peak value of fuel centerline temperature must not exceed 4700°F. Second, the minimum DNB Ratio (DNBR) in the core must not be less than the applicable design limit in normal operation or in short term transients.

In addition to the above, the peak linear power density and the nuclear enthalpy rise hot channel factor must not exceed their limiting values which result from the large break loss of coolant accident analysis based on the Emergency Core Cooling System acceptance criteria limit of 2200°F on peak clad temperature. This is required to meet the initial conditions assumed for the loss of coolant accident. To aid in specifying the limits of power distribution, the following hot channel factors are defined:

> $F_Q(Z)$, Height Dependent Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerance on fuel pellets and rods.
>
> F_Q^E, Engineering Heat Flux Hot Channel Factor, is defined as the allowance on heat flux required for manufacturing tolerances. The engineering factor allows for local variations in enrichment, pellet density and diameter, surface area of the fuel rod, and eccentricity of the gap between pellet and clad. Combined statistically the net effect is a factor of 1.03 to be applied to fuel rod surface heat flux for non-statistical applications.
>
> $F_{\Delta H}^N$, Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power for both loss of coolant accident and non-loss of coolant accident considerations.

It should be noted that the enthalpy rise factors are based on integrals and are used as such in the DNB and loss of coolant accident calculations. Local heat fluxes are obtained by using hot channel and adjacent channel explicit power shapes which take into account variations in radial (x-y) power shapes throughout the core. Thus, the radial power shape at the point of maximum heat flux is not necessarily directly related to the enthalpy rise factors. The results of the loss of coolant accident analyses are conservative with respect to the Emergency Core Cooling System acceptance criteria as specified in 10 CFR 50.46 using the upper bound $F_Q(Z)$ times the hot channel factor normalized operating envelope given in the CORE OPERATING LIMITS REPORT.

When an F_Q measurement is taken, measurement error, manufacturing tolerances, and the effects of rod bow must be allowed for. Five percent is the appropriate allowance for measurement error for a full core map (greater than or equal to 38 thimbles, including a minimum of 2 thimbles per core quadrant, monitored) taken with the movable incore detector flux mapping system, three percent is the appropriate allowance for manufacturing tolerances, and five percent is appropriate allowance for rod bow. These uncertainties are statistically combined and result in a net increase of 1.08 that is applied to the measured value of F_Q.

In the $F^N_{\Delta H}$ limit specified in the CORE OPERATING LIMITS REPORT, there is a four percent error allowance, which means that normal operation of the core is expected to result in $F^N_{\Delta H} \leq$ CFDH [1 + PFDH (1-P)]/1.04. The 4% allowance is based on the considerations that (a) normal perturbations in the radial power shape (e.g., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q, (b) the operator has a direct influence on F_Q through movement of rods and can limit it to the desired value; he has no direct control over $F^N_{\Delta H}$, and (c) an error in the predictions for radial power shape, which may be detected during startup physics tests and which may influence F_Q, can be compensated for by tighter axial control. An appropriate allowance for the measurement uncertainty for $F^N_{\Delta H}$ obtained from a full core map (≥ 38 thimbles, including a minimum of 2 detectors per core quadrant, monitored) taken with the movable incore detector flux mapping system has been incorporated in the statistical DNBR limit.

Measurement of the hot channel factors are required as part of startup physics tests, during each effective full power month of operation, and whenever abnormal power distribution conditions require a reduction of core power to a level based on measured hot channel factors. The incore map taken following core loading provides confirmation of the basic nuclear design bases including proper fuel loading patterns. The periodic incore mapping provides additional assurance that the nuclear design bases remain inviolate and identify operational anomalies which would, otherwise, affect these bases.

For normal operation, it has been determined that, provided certain conditions are observed, the enthalpy rise hot channel factor $F^N_{\Delta H}$ limit will be met. These conditions are as follows:

1. Control rod assemblies in a single bank move together with no individual control rod assembly insertion differing by more than 15 inches from the bank demand position. An indicated misalignment limit of 13 steps precludes a control rod assembly misalignment no greater than 15 inches with consideration of maximum instrumentation error.
2. Control rod banks are sequenced with overlapping banks as shown in the Control Bank Insertion Limits specified in the CORE OPERATING LIMITS REPORT.

3. The full length Control Bank Insertion Limits specified in the CORE OPERATING LIMITS REPORT are not violated.

4. Axial power distribution control procedures, which are given in terms of flux difference control and control bank insertion limits are observed. Flux difference refers to the difference between the top and bottom halves of two-section excore neutron detectors. The flux difference is a measure of the axial offset which is defined as the difference in normalized power between the top and the bottom halves of the core.

The permitted relaxation in $F^N_{\Delta H}$ with decreasing power level allows radial power shape changes with rod insertion to the insertion limits. It has been determined that provided the above conditions 1 through 4 are observed, this hot channel factor limit is met.

A recent evaluation of DNB test data obtained from experiments of fuel rod bowing in thimble cells has identified that the reduction in DNBR due to rod bowing in thimble cells is more than completely accommodated by existing thermal margins in the core design. Therefore, it is not necessary to continue to apply a rod bow penalty to $F^N_{\Delta H}$.

The procedures for axial power distribution control are designed to minimize the effects of xenon redistribution on the axial power distribution during load-follow maneuvers. Basically, control of flux difference is required to limit the difference between the current value of flux difference (ΔI) and a reference value which corresponds to the full power equilibrium value of axial offset (axial offset = ΔI/fractional power). The reference value of flux difference varies with power level and burnup, but expressed as axial offset it varies only with burnup.

The technical specifications on power distribution control given in Specification 3.12.B.4 together with the surveillance requirements given in Specification 3.12.B.2 assure that the Limiting Condition for Operation for the heat flux hot channel factor is met.

The target (or reference) value of flux difference is determined as follows. At any time that equilibrium xenon conditions have been established, the indicated flux difference is noted with the full length rod control bank more than 190 steps withdrawn (i.e., normal full power operating position appropriate for the time in life, usually withdrawn farther as burnup proceeds). This value, divided by the fraction of full power at which the core was operating, is the full power value of the target flux difference. Values for all other core power levels are obtained by multiplying the full power value by the fractional power. Since the indicated equilibrium value was noted, no allowances for excore detector error are necessary and indicated deviation of ±5% ΔI are permitted from the indicated reference value. During periods where extensive load following is required, it may be impractical to establish the required core conditions for measuring the target flux difference every month. For this reason, the specification provides two methods for updating the target flux difference.

Strict control of the flux difference (and rod position) is not as necessary during part power operation. This is because xenon distribution control at part power is not as significant as the control at full power and allowance has been made in predicting the heat flux peaking factors for less strict control at part power. Strict control of the flux difference is not always possible during certain physics tests or during excore detector calibrations. Therefore, the specifications on power distribution control are less restrictive during physics tests and excore detector calibrations; this is acceptable due to the low probability of a significant accident occurring during these operations.

In some instances of rapid unit power reduction automatic rod motion will cause the flux difference to deviate from the target band when the reduced power level is reached. This does not necessarily affect the xenon distribution sufficiently to change the envelope of peaking factors which can be reached on a subsequent return to full power within the target band. However, to simplify the specification, a limitation of one hour in any period of 24 hours is placed on operation outside the band. This ensures that the resulting xenon distributions are not significantly different from those resulting from operation within the target band. The instantaneous consequences of being outside the band, provided rod insertion limits are observed, is not worse than a 10 percent increment in peaking factor for the allowable flux difference at 90% power, in the range ±13.8 percent (±10.8 percent indicated) where for every 2 percent below rated power, the permissible flux difference boundary is extended by 1 percent.

As discussed above, the essence of the procedure is to maintain the xenon distribution in the core as close to the equilibrium full power condition as possible. This is accomplished, by using the boron system to position the full length control rod assemblies to produce the required indicated flux difference.

A 2% QUADRANT POWER TILT allows that a 5% tilt might actually be present in the core because of insensitivity of the excore detectors for disturbances near the core center such as misaligned inner control rod assembly and an error allowance. No increase in F_Q occurs with tilts up to 5% because misaligned control rod assemblies producing such tilts do not extend to the unrodded plane, where the maximum F_Q occurs.

The QPTR limit must be maintained during power operation with THERMAL POWER > 50% of RATED POWER to prevent core power distributions from exceeding the design limits.

Applicability during power operation ≤ 50% RATED POWER or when shut down is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RATED POWER or lower.

The limits of the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the UFSAR assumptions and have been analytically demonstrated to be adequate to maintain a minimum DNBR which is greater than the design limit throughout each analyzed transient. Measurement uncertainties are accounted for in the DNB design margin. Therefore, measurement values are compared directly to the surveillance limits without applying instrument uncertainty.

The 12 hour periodic surveillance of temperature and pressure through instrument readout is sufficient to ensure that these parameters are restored to within their limits following load changes and other expected transient operation. The 12 hour surveillance of RCS total flow rate, by installed flow instrumentation, is sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions. Measurement of RCS total flow rate by performance of a precision calorimetric heat balance specified in TS Table 4.1-2A allows for the installed RCS flow instrumentation to be calibrated and verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

TABLE 3.12-1

ACCIDENT ANALYSES REQUIRING REEVALUATION IN THE EVENT OF AN INOPERABLE CONTROL ROD ASSEMBLY

Control Rod Assembly Insertion Characteristics

Control Rod Assembly Misalignment

Large and Small Break Loss of Coolant Accidents

Single Reactor Coolant Pump Locked Rotor

Major Secondary Pipe Rupture

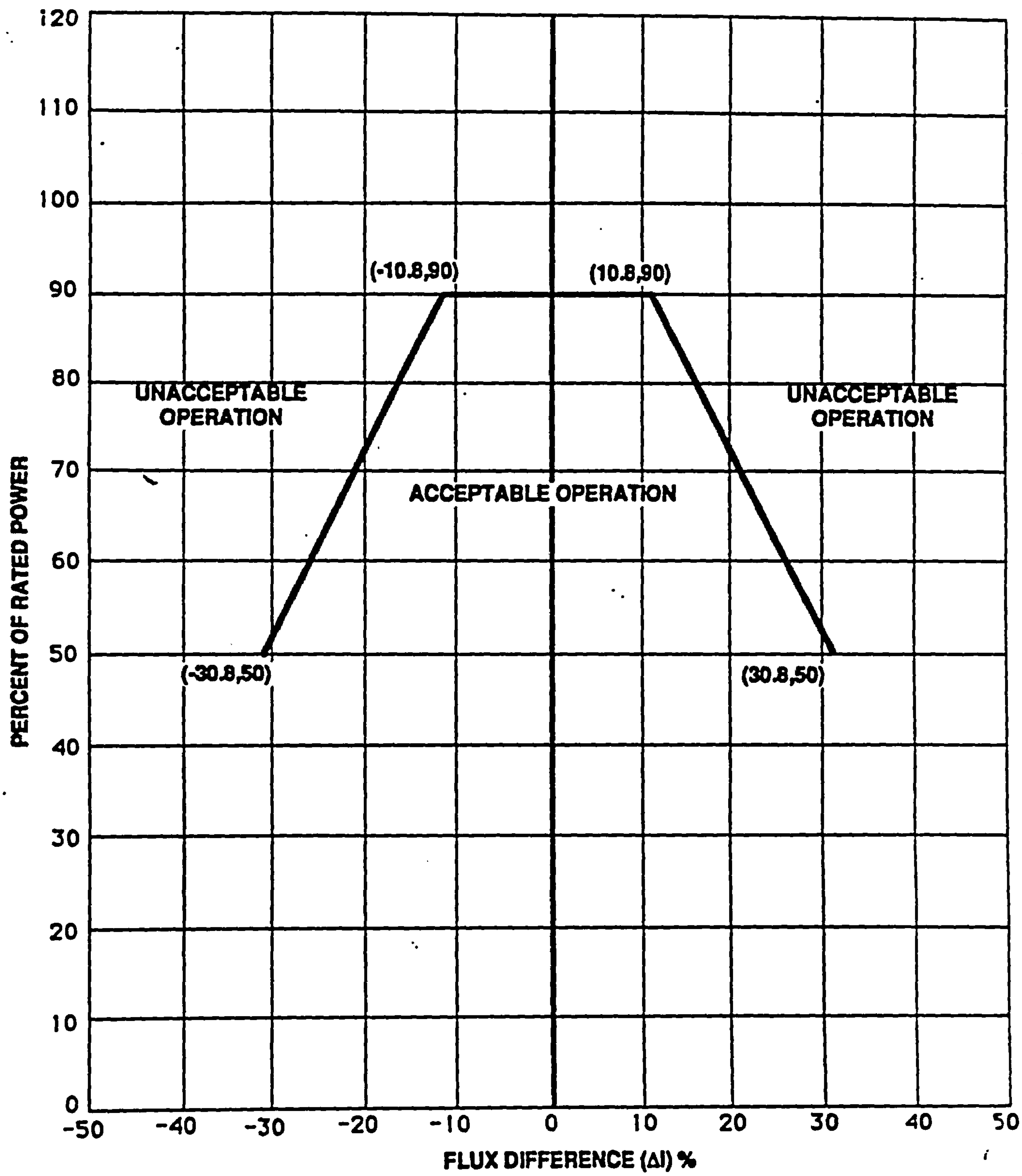
Rupture of a Control Rod Drive Mechanism Housing
(Control Rod Assembly Ejection)

DELETED

DELETED

DELETED

AXIAL FLUX DIFFERENCE LIMITS AS A FUNCTION OF RATED POWER SURRY POWER STATION



3.13 COMPONENT COOLING SYSTEM

Applicability

Applies to the operational status of all subsystems of the Component Cooling System. The Component Cooling System consists of the Component Cooling Water Subsystem, Chilled Component Water Subsystem, Chilled Water Subsystem, and Neutron Shield Tank Cooling Water Subsystem.

Objective

To define limiting conditions for each subsystem of the Component Cooling System necessary to assure safe operation of each reactor unit of the station during startup, POWER OPERATION, or cooldown.

Specifications

A. When a unit's Reactor Coolant System temperature and pressure exceed 350°F and 450 psig, respectively, or when a unit's reactor is critical operating conditions for the Component Cooling Water Subsystem shall be as follows:

1. For one unit operation, two component cooling water pumps and heat exchangers shall be OPERABLE.

2. For two unit operation, three component cooling water pumps and heat exchangers shall be OPERABLE.

B. During POWER OPERATION, Specification A.1 or A.2 above may be modified to allow one of the required components to be inoperable provided immediate attention is directed to making repairs. If the system is not restored within 24 hours to the requirements of Specification A.1 or A.2, an operating reactor shall be placed in HOT SHUTDOWN within the next 6 hours. If the repairs are not completed within an additional 48 hours, the affected reactor shall be placed in COLD SHUTDOWN within the following 30 hours.

C. When the average reactor coolant loop temperature is less than or equal to 350°F, the Component Cooling Water Subsystem shall be OPERABLE for immediate supply of cooling water to the residual heat removal heat exchangers, if required.

D. If the requirements of Specification C are not satisfied resulting in Residual Heat Removal System inoperability, immediate attention shall be directed to making repairs and the requirements in Specification 3.1.A.1.d, 3.10.A.4, or 3.10.A.5, as applicable, shall be satisfied.

E. Whenever the component cooling water radiation monitor is inoperable, the surge tank vent valve shall remain closed.

Basis

The Component Cooling System is an intermediate cooling system which serves both reactor units. It transfers heat from heat exchangers containing reactor coolant, other radioactive liquids, and other fluids to the Service Water System. The Component Cooling System is designed to (1) provide cooling water for the removal of residual and sensible heat from the Reactor Coolant System during shutdown, cooldown, and startup, (2) cool the containment recirculation air coolers and the reactor coolant pump motor coolers, (3) cool the letdown flow in the Chemical and Volume Control System during POWER OPERATION, and during residual heat removal for continued purification, (4) cool the reactor coolant pump seal water return flow, (5) provide cooling water for the neutron shield tank and (6) provide cooling to dissipate heat from other reactor unit components.

The Component Cooling Water Subsystem has four component cooling water pumps and four component cooling water heat exchangers. Each of the component cooling water heat exchangers is designed to remove during normal operation the entire heat load from one unit plus one half of the heat load common to both units. Thus, one component cooling water pump and one component cooling water heat exchanger are required for each unit which is at POWER OPERATION. Two pumps and two heat exchangers are normally operated during the removal of residual and sensible heat from one unit during cooldown. Failure of a single component may extend the time required for cooldown but does not effect the safe operation of the station.

References

UFSAR Section 5.3, Containment Systems
UFSAR Section 9.4, Component Cooling System
UFSAR Section 15.5.1.2, Containment Design Criteria

3.14 CIRCULATING AND SERVICE WATER SYSTEMS

Applicability

Applies to the operational status of the Circulating and Service Water Systems.

Objective

To define those limiting conditions of the Circulating and Service Water Systems necessary to assure safe station operation.

Specification

A. The Reactor Coolant System temperature or pressure of a reactor unit shall not exceed 350° F or 450 psig, respectively, or the reactor shall not be critical unless:

   1. The high level intake canal is filled to at least elevation +23.0 feet at the high level intake structure.

   2. Unit subsystems, including piping and valves, shall be operable to the extent of being able to establish the following:

      a. Flow to and from one bearing cooling water heat exchanger.

      b. Flow to and from the component cooling heat exchangers required by Specification 3.13.

   3. At least two circulating water pumps are operating or are operable.

   4. Three emergency service water pumps are operable; these pumps will service both units simultaneously.

5. Two service water flow paths to the charging pump service water subsystem are OPERABLE.

6. Two service water flow paths to the recirculation spray subsystems are OPERABLE.

7. Two service water flow paths to the main control room and emergency switchgear room air conditioning subsystems are OPERABLE.

B. The requirements of Specification 3.14.A.4 may be modified to allow one Emergency Service Water pump to remain inoperable for a period not to exceed 14 days. If this pump is not OPERABLE in 14 days, then place both units in HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the next 30 hours.

The requirements of 3.14.A.4 may be modified to have two Emergency Service Water pumps OPERABLE with one unit in COLD SHUTDOWN with combined Spent Fuel pit and shutdown unit decay heat loads of 25 million BTU/HR or less. One of the two remaining pumps may be inoperable for a period not to exceed 14 days. If this pump is not OPERABLE in 14 days, then place the operating unit in HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the next 30 hours.

C. The requirements of Specifications 3.14.A.5 and 3.14.A.7 may be modified to allow unit operation with only one OPERABLE flow path to the charging pump service water subsystem and to the main control and emergency switchgear rooms air conditioning condensers. If the affected systems are not restored to the requirements of Specifications 3.14.A.5 and 3.14.A.7 within 72 hours, the reactor shall be placed in HOT SHUTDOWN within the next 6 hours. If the requirements of Specifications 3.14.A.5 and 3.14.A.7 are not satisfied as allowed by this Specification, the reactor shall be placed in COLD SHUTDOWN within the next 30 hours.

D. The requirements of Specification 3.14.A.6 may be modified to allow unit operation with only one OPERABLE flow path to the recirculation spray subsystems. If the affected system is not restored to the requirements of Specification 3.14.A.6 within 24 hours, the reactor shall be placed in HOT SHUTDOWN within the next 6 hours. If the requirements of Specification 3.14.A.6 are not met within an additional 48 hours, the reactor shall be placed in COLD SHUTDOWN within the next 30 hours.

Basis

The Circulating and Service Water Systems are designed for the removal of heat resulting from the operation of various systems and components of either or both of the units. Untreated water, supplied from the James River and stored in the high level intake canal is circulated by gravity through the recirculation spray coolers and the bearing cooling water heat exchangers and to the charging pumps lubricating oil cooler service water pumps which supply service water to the charging pump lube oil coolers.

In addition, the Circulating and Service Water Systems supply cooling water to the component cooling water heat exchangers and to the main control and emergency switchgear rooms air conditioning condensers. The Component Cooling heat exchangers are used during normal plant operations to cool various station components and when in shutdown to remove residual heat from the reactor. Component Cooling is not required on the accident unit during a loss-of-coolant accident. If the loss-of-coolant accident is coincident with a loss of off-site power, the nonaccident unit will be maintained at HOT SHUTDOWN with the ability to reach COLD SHUTDOWN.

The long term Service Water requirement for a loss-of-coolant accident in one unit with simultaneous loss-of-station power and the second unit being brought to HOT SHUTDOWN is greater than 15,000 gpm. Additional Service Water is necessary to bring the nonaccident unit to COLD SHUTDOWN. Three diesel driven Emergency Service Water pumps with a design capacity of 15,000 gpm each, are provided to supply water to the High Level Intake canal during a loss-of-station power incident. Thus, considering the single active failure of one pump, three Emergency Service Water pumps are required to be OPERABLE. The allowed outage time of 14 days provides operational flexibility to allow for repairs up to and including replacement of an Emergency Service Water pump without forcing dual unit outages, yet limits the amount of operating time without the specified number of pumps.

When one Unit is in Cold Shutdown and the heat load from the shutdown unit and spent fuel pool drops to less than 25 million BTU/HR, then one Emergency Service Water pump may be removed from service for the subsequent time that the unit remains in Cold Shutdown due to the reduced residual heat removal and hence component cooling requirements.

A minimum level of +17.2 feet in the High Level Intake canal is required to provide design flow of Service Water through the Recirculation Spray heat exchangers during a loss-of-coolant accident for the first 24 hours. If the water level falls below +23' 6", signals are generated to trip both unit's turbines and to close the nonessential Circulating and Service Water valves. A High Level Intake canal level of +23' 6" ensures actuation prior to canal level falling to elevation +23'. The Circulating Water and Service Water isolation valves which are required to close to conserve Intake Canal inventory are periodically verified to limit total leakage flow out of the Intake Canal. In addition, passive vacuum breakers are installed on the Circulating Water pump discharge lines to assure that a reverse siphon is not continued for canal levels less than +23 feet when Circulating Water pumps are de-energized. The remaining six feet of canal level is provided coincident with ESW pump operation as the required source of Service Water for heat loads following the Design Basis Accident.

References:

UFSAR Section 9.9	Service Water System
UFSAR Section 10.3.4	Circulating Water System
UFSAR Section 14.5	Loss-of-Coolant Accidents, Including the Design Basis Accident

3.16 EMERGENCY POWER SYSTEM

Applicability

Applies to the availability of electrical power for safe operation of the station during an emergency.

Objective

To define those conditions of electrical power availability necessary to shutdown the reactor safely, and provide for the continuing availability of Engineered Safeguards when normal power is not available.

Specification

A. A reactor shall not be made critical nor shall a unit be operated such that the reactor coolant system pressure and temperature exceed 450 psig and 350°F, respectively, without:

1. Two diesel generators (the unit diesel generator and the shared backup diesel generator) OPERABLE with each generator's day tank having at least 290 gallons of fuel and with a minimum on-site supply of 35,000 gal of fuel available.

2. Two 4,160V emergency buses energized.

3. Four 480V emergency buses energized.

4. Two physically independent circuits from the offsite transmission network to energize the 4,160V and 480V emergency buses. One of these sources must be immediately available (i.e. primary source) and the other must be capable of being made available within 8 hours (i.e. dependable alternate source).

5. Two OPERABLE flow paths for providing fuel to each diesel generator.

6. Two station batteries, two chargers, and the DC distribution systems OPERABLE.

7. Emergency diesel generator battery, charger and the DC control circuitry OPERABLE for the unit diesel generator and for the shared back-up diesel generator.

B. During POWER OPERATION or the return to power from HOT SHUTDOWN, the requirements of specification 3.16-A may be modified by one of the following:

1.a. With either unit's dedicated diesel generator or shared backup diesel generator unavailable or inoperable:

1. Verify the operability of two physically independent offsite AC circuits within one hour and at least once per eight hours thereafter.

2. Within 24 hours, determine that the OPERABLE diesel generator is not inoperable due to common cause failure or demonstrate the operability of the remaining OPERABLE diesel generator by performing Surveillance Requirement 4.6.A.1.a. For the purpose of operability testing, the second diesel generator may be inoperable for a total of two hours per test provided the two offsite AC circuits have been verified OPERABLE prior to testing.

3. If this diesel generator is not returned to an OPERABLE status within 7 days, the reactor shall be brought to HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

1.b. One diesel fuel oil flow path may be "inoperable" for 24 hours provided the other flow path is proven OPERABLE. If after 24 hours, the inoperable flow path cannot be returned to service for reasons other than buried fuel oil storage tank inspection and related repair, the diesel shall be considered "inoperable." When the emergency diesel generator battery, charger or DC control circuitry is inoperable, the diesel shall be considered "inoperable."

2. If a primary source is not available, the unit may be operated for seven (7) days provided the dependable alternate source can be OPERABLE within 8 hours. If specification A-4 is not satisfied within seven (7) days, the unit shall be brought to COLD SHUTDOWN.

3. One battery may be inoperable for 24 hours provided the other battery and battery chargers remain OPERABLE with one battery charger carrying the DC load of the failed battery's supply system. If the battery is not returned to OPERABLE status within the 24 hour period, the reactor shall be placed in HOT SHUTDOWN. If the battery is not restored to OPERABLE status within an additional 48 hours, the reactor shall be placed in COLD SHUTDOWN.

4. One buried fuel oil storage tank may be inoperable for 7 days for tank inspection and related repair, provided the following actions are taken:

   a. prior to removing the tank from service, verify that 50,000 gallons of replacement fuel oil is available offsite and transportation is available to deliver that volume of fuel oil within 48 hours, and

   b. prior to removing the tank from service and at least once every 12 hours, verify that the remaining buried fuel oil storage tank contains ≥ 17,500 gallons, and

   c. prior to removing the tank from service and at least once every 12 hours, verify that the above ground fuel oil storage tank contains ≥ 50,000 gallons.

If these conditions are not satisfied or if the buried fuel oil storage tank is not returned to OPERABLE status within 7 days, both units shall be placed in HOT SHUTDOWN within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

C. The continuous running electrical load supplied by an emergency diesel generator shall be limited to 2750 KW.

Basis

The Emergency Power System is an on-site, independent, automatically starting power source. It supplies power to vital unit auxiliaries if a normal power source is not available. The Emergency Power System consists of three diesel generators for two units. The Unit 1 diesel generator and the Unit 2 diesel generator are dedicated to emergency buses 1H and 2H, respectively. A third diesel generator is provided as a "swing diesel" and is shared by Units 1 and 2. Upon receipt of a safety injection signal on a unit, the shared diesel generator automatically aligns to either emergency bus 1J (Unit 1) or 2J (Unit 2) as a backup power supply for the accident unit. The shared diesel is configured to preferentially load to the Unit 2 emergency bus on a loss of offsite power without a safety injection signal. The Unit 1 and Unit 2 diesel generators also supply power for certain common or shared plant systems/components. The diesel generators have a cumulative 2,000 hour rating of 2750 KW. The actual loads are verified by engineering calculation to remain below the 2750 kw limit.

ratings for accident conditions, require approximately 2,320 kw. Each unit has two emergency buses, one bus in each unit is connected to its exclusive diesel generator. The second bus in each unit will be connected to the backup diesel generator as required. Each diesel generator has 100 percent capacity and is connected to independent 4,160 v emergency buses. These emergency buses are normally fed from the reserve station service transformers. The normal station service transformers are fed from the unit isolated phase bus at a point between the generator terminals and the low voltage terminal of the main step-up transformer. The reserve station service transformers are fed from the system reserve transformer in the high voltage switchyard. The circuits which supply power through either system reserve transformer are called "primary source." In the event a system reserve transformer is inoperable, the remaining one may be cross-tied by a 34.5 bus to all three reserve station service transformers. Thus, a primary source is available to both units even if one of the two system reserve transformers is out of service. Verification of primary source operability is performed by confirming that the reserve station service transformers are energized.

In addition to the "primary sources," each unit has an additional off-site power source which is called the "dependable alternate source." This source can be made available in eight (8) hours by removing a unit from service, disconnecting its generator from the isolated phase bus, and feeding offsite power through the main step-up transformer and normal station service transformers to the emergency buses.

The generator can be disconnected from the isolated phase bus within eight (8) hours. A unit can be maintained in a safe condition for eight (8) hours with no off-site power without damaging reactor fuel or the reactor coolant pressure boundary.

Verification of the dependable alternate source operability is accomplished by verifying that the required circuits, transformers, and circuit breakers are available.

The diesel generators function as an on-site back-up system to supply the emergency buses. Each emergency bus provides power to the following operating Engineered Safeguards equipment:

A. One containment spray pump

B. One charging pump

C. One low head safety injection pump

D. One recirculation spray pump inside containment

E. One recirculation spray pump outside containment

F. One containment vacuum pump

G. One motor-driven auxiliary steam generator feedwater pump

H. One motor control center for valves, instruments, control air compressor, fuel oil pumps, etc.

I. Control area air conditioning equipment - four air recirculating units, two water chilling units, one service water pump, and two chilled water circulating pumps

J. One charging pump service water pump

The day tanks are filled by transferring fuel from any one of two buried tornado missile protected fuel oil storage tanks, each of 20,000 gal capacity. Two of 100 percent capacity fuel oil transfer pumps per diesel generator are powered from the emergency buses to assure that an operating diesel generator has a continuous supply of fuel. The buried fuel oil storage tanks contain a seven (7) day supply of fuel, 35,000 gal minimum, for the full load operation of one diesel generator; in addition, there is an above ground fuel oil storage tank on-site with a capacity of 210,000 gal which is used for transferring fuel to the buried tanks.

One of the two buried fuel oil storage tanks may be inoperable to permit inspection and related repair of that buried fuel oil storage tank. While one tank is removed from service, the remaining buried fuel oil storage tank supplies fuel oil to the EDGs of both units. Prior to removal of one buried tank from service and while it is inoperable, verification of the volume in the remaining buried fuel oil storage tank and the above ground fuel oil storage tank is required to ensure an adequate source of fuel oil remains available onsite. In addition, verification of the offsite replacement fuel oil supply is also required. While one buried tank is out of service, the verification of the onsite and offsite fuel oil sources continues to support full load operation of one diesel generator for seven days.

If a loss of normal power is not accompanied by a loss-of-coolant accident, the safeguards equipment will not be required. Under this condition the following additional auxiliary equipment may be operated from each emergency bus:

A. One component cooling pump

B. One residual heat removal pump

C. One motor-driven auxiliary steam generator feedwater pump

The emergency buses in each unit are capable of being interconnected under strict administrative procedures so that the equipment which would normally be operated by one of the diesels could be operated by the other diesel, if required.

The electrical power requirements and the emergency power testing requirements for the auxiliary feedwater cross-connect are contained in TS 3.6.C.4.c and TS 4.6 respectively.

TS action statement 3.16.B.1.a.2 provides an allowance to avoid unnecessary testing of an OPERABLE EDG(s). If it can be determined that the cause of an inoperable EDG does not exist on the OPERABLE EDG(s), operability testing does not have to be performed. If the cause of the inoperability exists on the other EDG(s), then the other EDG(s) would be declared inoperable upon discovery, and the applicable required action(s) would be entered. Once the failure is repaired, the common cause failure no longer exists and the operability testing requirement for the OPERABLE EDG(s) is satisfied. If the cause of the initial inoperable EDG cannot be confirmed not to exist on the remaining EDG(s), performance of the operability test within 24 hours provides assurance of continued operability of those EDG(s).

In the event the inoperable EDG is restored to OPERABLE status prior to completing the operability testing requirement for the OPERABLE EDG(s), the corrective action program will continue to evaluate the common cause possibility, including the other unit's EDG or the shared EDG. This continued evaluation, however, is no longer under the 24-hour constraint imposed by the action statement.

According to Generic Letter 84-15 (Ref. 6), 24 hours is reasonable to confirm that the OPERABLE EDG(s) is not affected by the same problem as the inoperable EDG.

References

(1) UFSAR Section 8.5 Emergency Power System

(2) UFSAR Section 9.3 Residual Heat Removal System

(3) UFSAR Section 9.4 Component Cooling System

(4) UFSAR Section 10.3.2 Auxiliary Steam System

(5) UFSAR Section 10.3.5 Condensate and Feedwater System

(6) Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," dated July 2, 1984

The verification of functionality of the AAC System prior to entering the temporary 14-day AOT will be based on the previous satisfactory quarterly test. The once per shift functionality check will be performed during shiftly operator rounds.

In addition to verifying and checking functionality of the AAC System prior to and during the temporary 14-day AOT, the following actions will also be taken:

- Weather conditions will be monitored and preplanned maintenance will not be scheduled if severe weather conditions are anticipated.
- The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the temporary 14-day AOT.
- Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or LOOP will be avoided. In addition, no discretionary switchyard maintenance will be performed.
- TS required systems, subsystems, trains, components, and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components, and devices.
- Operation or maintenance of plant equipment when its redundant equipment or train is out of service will be controlled in accordance with procedure OP-SU-601, "Protected Equipment." The Unit 1 steam-driven Auxiliary Feedwater Pump will be controlled as "Protected Equipment" during the temporary 14-day AOT.
- The status of the AAC diesel generator, EDGs, RSST A and RSST B will be monitored once per shift.

References

(1) UFSAR Section 8.5 Emergency Power System

(2) UFSAR Section 9.3 Residual Heat Removal System

(3) UFSAR Section 9.4 Component Cooling System

(4) UFSAR Section 10.3.2 Auxiliary Steam System

(5) UFSAR Section 10.3.5 Condensate and Feedwater System

(6) Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," dated July 2, 1984

3.17 LOOP STOP VALVE OPERATION

Applicability

Applies to the operation of the loop stop valves.

Objective

To specify those limiting conditions for operation of the loop stop valves which must be met to ensure safe reactor operation.

Specifications

1. The loop stop valves shall be maintained open unless the reactor is in COLD SHUTDOWN or REFUELING SHUTDOWN.

2. A hot or cold leg stop valve in a reactor coolant loop may be closed in COLD SHUTDOWN or REFUELING SHUTDOWN for up to 2 hours for valve maintenance or testing. If the stop valve is not opened within 2 hours, the loop shall be isolated.

3. Whenever a reactor coolant loop is isolated, the stop valves of the isolated loop shall have their AC power removed and their breakers locked open.*

4. Whenever an isolated and filled reactor coolant loop is returned to service, the following conditions shall be met:

   a. A source range nuclear instrumentation channel shall be operable and continuously monitored with audible indication in the control room during opening of the hot leg loop stop valve, during relief line flow, and when opening the cold leg stop valve in the isolated loop. Should the count rate increase by more than a factor of two over the initial count rate, the hot and cold leg stop valves shall be re-closed and no attempt made to open the stop valves until the reason for the count rate increase has been determined.

* Power may be restored to a hot or cold leg loop stop valve in an isolated and filled loop provided the requirements of Specifications 4.b or 4.c are met, respectively. Power may be restored to a loop stop valve in an isolated and drained loop provided the requirements of Specifications 5.a and b are met.

b. Before opening the hot leg loop stop valve.

1) The boron concentration of the isolated loop shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.7, as applicable for the active volume of the Reactor Coolant System. Verification of this condition shall be completed within 1 hour prior to opening the hot leg stop valve in the isolated loop.

c. Before opening the cold leg loop stop valve.

1) The hot leg loop stop valve shall be open with relief line flow established for at least 90 minutes at greater than or equal to 125 gpm.

2) The cold leg temperature of the isolated loop shall be at least 70°F and within 20°F of the highest cold leg temperature of the active loops. Verification of this condition shall be completed within 30 minutes prior to opening the cold leg stop valve in the isolated loop.

3) The boron concentration of the isolated loop shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.7, as applicable for the active volume of the Reactor Coolant System. Verification of this condition shall be completed after relief line flow for at least 90 minutes at greater than or equal to 125 gpm and within 1 hour prior to opening the cold leg stop valve in the isolated loop.

5. Whenever an isolated and drained reactor coolant loop is filled from the active volume of the RCS, the following conditions shall apply:

a. Seal injection may be initiated to the reactor coolant pump in the isolated loop provided that:

1) The isolated loop is drained. Verification of this condition shall be completed within 2 hours prior to initiating seal injection.

2) The boron concentration of the source for reactor coolant pump seal injection shall be greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.7, as applicable for the active volume of the Reactor Coolant System. If using the Volume Control Tank (VCT) as the source for reactor coolant pump seal injection, verification of the boron concentration shall be completed within 1 hour prior to initiating seal injection and every hour thereafter during the loop backfill evolution.

b. The cold leg loop stop valve may be energized and/or opened to backfill the loop from the active volume of the Reactor Coolant System provided that:

1) The isolated loop is drained or reactor coolant pump seal injection has been initiated in accordance with Specification 3.17.5.a above. Verification of the loop being drained shall be completed within 2 hours prior to partially opening the cold leg stop valve in the isolated loop.

2) The Reactor Coolant System level is at least 18 ft.

3) A source range nuclear instrumentation channel is OPERABLE with audible indication in the control room.

c. Backfilling of the isolated loop may continue provided that:

1) The Reactor Coolant System level is maintained at or above 18 ft. If Reactor Coolant System level is not maintained at or above 18 ft. the loop stop valve shall be closed.

2) The boron concentration of the reactor coolant pump seal injection source is greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.7, as applicable for the active volume of the Reactor Coolant System. If the boron concentration is not maintained greater than or equal to the required boron concentration noted above, the loop stop valve on the loop being backfilled shall be closed and either drain the loop or apply Specification 3.17.4.

3) A source range nuclear instrumentation channel is OPERABLE and continuously monitored with audible indication in the control room during the backfill evolution. Should the count rate increase by more than a factor of two over the initial count rate, the cold leg loop stop valve shall be closed and no attempt made to open the cold leg stop valve until the reason for the count rate increase has been determined.

d. When the isolated loop is full, the cold leg loop stop valve can be fully opened and the hot leg loop stop valve opened provided that:

1) The boron concentration of the isolated loop is greater than or equal to the boron concentration corresponding to the shutdown margin requirements of Specification 1.0.C.2 or 3.10.A.7, as applicable for the active volume of the Reactor Coolant System. If the VCT was used as the source for reactor coolant pump seal injection, this condition shall be verified within 1 hour prior to fully opening the loop stop valves. If the boron concentration in the isolated loop does not meet the condition above, close the loop stop valve and either drain the loop or apply Specification 3.17.4.

2) The hot and cold leg loop stop valves are opened within 2 hours after the isolated loop is filled. If the loop stop valves are not fully open within 2 hours, close the loop stop valves and either drain the loop or apply Specification 3.17.4.

<u>Basis</u>

The Reactor Coolant System may be operated with isolated loops in COLD SHUTDOWN or REFUELING SHUTDOWN in order to perform maintenance. A loop stop valve in any loop can be closed for up to two hours without restriction for testing or maintenance in these operating conditions. While operating with a loop isolated, AC power is removed from the loop stop valves and their breakers locked opened to prevent inadvertent opening. When the isolated loop is returned to service, the coolant in the isolated loop mixes with the coolant in the active loops. This situation has the potential of causing a positive reactivity addition with a corresponding reduction of shutdown margin if:

a. The temperature in the isolated loop is lower than the temperature in the active loops (cold water accident), or

b. The boron concentration in the isolated loop is insufficient to maintain the required shutdown margin (boron dilution accident).

The return to service of an isolated and filled loop is done in a controlled manner that precludes the possibility of an uncontrolled positive reactivity addition from cold water or boron dilution. A flow path to mix the isolated loop with the active loops is established through the relief line by opening the hot leg stop valve in the isolated loop and starting the reactor coolant pump. The relief line flow is low enough to limit the rate of any reactivity addition due to differences in temperature and boron concentration between the isolated loop and the active loops. In addition, a source range instrument channel is required to be operable and continuously monitored to detect any change in core reactivity.

The limiting conditions for returning an isolated and filled loop to service are as follows:

a. A hot leg loop stop valve may not be opened unless the boron concentration in the isolated loop is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

b. A cold leg loop stop valve can not be opened unless the hot leg loop stop valve is open with relief line flow established for at least 90 minutes at greater than or equal to 125 gpm. In addition, the cold leg temperature of the isolated loop must be at least 70°F and within 20°F of the highest cold leg temperature of the active loops. The boron concentration in the isolated loop must be verified to be greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

c. A source range nuclear instrument channel is required to be monitored to detect any unexpected positive reactivity addition during hot or cold leg stop valve opening and during relief line flow.

If an isolated loop is initially drained, the above requirements are not applicable. An initially isolated and drained loop may be returned to service by partially opening the cold leg loop stop valve and filling the loop in a controlled manner from the Reactor Coolant System. To eliminate numerous reactor coolant pump jogs to completely fill a drained loop, a partial vacuum may be established in the isolated loop prior to commencing filling from the active volume of the Reactor Coolant System. The vacuum-assist loop fill evolution requires initiating seal injection to the reactor coolant pump to permit establishing an adequate vacuum in the isolated loop. A portion of the reactor coolant pump seal injection enters the isolated loop. To preclude the possibility of an uncontrolled positive reactivity addition associated with the water injected into the isolated and drained loop from the seal injection, a water source of known boron concentration is used.

Prior to initiating seal injection to the reactor coolant pump in an isolated loop or partially opening the cold leg loop stop valve, the following measures are required to ensure that no uncontrolled positive reactivity addition or loss of Reactor Coolant System inventory occurs:

a. The isolated loop is verified drained prior to the initial addition of water to return a loop to service, thus preventing the dilution of the Reactor Coolant System boron concentration by liquid present in the loop. Therefore, verification that the loop is drained must occur either prior to initiation of seal injection to the Reactor Coolant Pump if the vacuum-assist backfill method is used or prior to opening the cold leg loop stop valve if the vacuum-assist backfill method is not used.

b. The Reactor Coolant System level is verified to be greater than or equal to the 18 ft. elevation to ensure Reactor Coolant System inventory is maintained for decay heat removal. In addition, the filling evolution is limited to one isolated loop at a time.

c. The water source for the reactor coolant pump seal injection is sampled to ensure the boron concentration is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

d. A source range nuclear instrument channel is monitored to detect any unexpected positive reactivity addition.

During the loop fill evolution. the following measures are implemented to ensure no positive reactivity additions or sudden loss of Reactor Coolant System inventory occur:

a. The Reactor Coolant System is maintained at greater than or equal to the 18 ft. elevation.

b. Makeup to the active portion of the Reactor Coolant System is through a flowpath that will ensure makeup flow is mixed with the reactor coolant in the active portion of the Reactor Coolant System and flows through the core prior to entering the loop being filled.

c. Charging flow from the VCT. if used as the source for reactor coolant pump seal injection. is periodically sampled to ensure the boron concentration is greater than or equal to the boron concentration corresponding to the shutdown margin requirements for the active portion of the Reactor Coolant System.

d. The source range nuclear instrumentation channel is monitored to provide a secondary indication of any possible positive reactivity addition.

The potential reactivity effects due to Reactor Coolant System cooldown during and following loop backfill are limited to acceptable levels by the small absolute value of the isothermal temperature coefficient of reactivity that exists at cold and refueling shutdown conditions. If steam generator secondary temperature is higher than the active portion of the Reactor Coolant System. a conservative heat transfer analysis demonstrates that 1) the pressurizer insurge rates that could result from heatup are easily accommodated by available relief capacity. and 2) the total integrated insurge due to heatup following backfill is very small. i.e.. less than the unmeasured pressurizer volume above the upper level tap.

Reactivity effects due to boron stratification in the backfilled loop are not a concern since stratification is not expected to take place at the normal shutdown boron concentrations (2000-2400 ppm) and temperatures (40°F-200°F) during the time to complete backfill of the loop and open the loop stop valves fully.

After an initially drained loop is filled from the Reactor Coolant System by partially opening the loop stop valves, the loop is no longer considered to be isolated. Thus, the requirements for returning an isolated and filled loop to service are not applicable and the loop stop valves may be fully opened without restriction within two hours of completing the loop fill evolution.

The initial Reactor Coolant System level requirement has been established such that, even if the three cold leg stop valves are suddenly opened and no makeup is available, the Reactor Coolant System water level will not drop below mid-nozzle level. This ensures continued adequate suction conditions for the residual heat removal pumps.

The safety analyses assume a minimum shutdown margin as an initial condition. Violation of these limiting conditions could result in the shutdown margin being reduced to less than that assumed in the safety analyses. In addition, violation of these limiting conditions could also cause a loss of shutdown decay heat removal.

Reference

(1) UFSAR Section 4.2

(2) UFSAR Section 14.2.5

3.18 MOVABLE IN-CORE INSTRUMENTATION

Applicability

Applies to the operability of the movable detector instrumentation system.

Objective

To specify functional requirements on the use of the in-core instrumentation systems, for the recalibration of the excore symmetrical off-set detection system.

Specification

A. A minimum of 16 total accessible thimbles and at least 2 per quadrant, each of which will accept a movable incore-detector, shall be operable during re-calibration of the excore symmetrical off-set detection system.

B. Power shall be limited to 90% of rated power for three loop operation, 54% of rated power for two loop operation with the loop stop valves closed, and 50% of rated power for two loop operation with the loop stop valves open if re-calibration requirements for the excore symmetrical off-set detection system, identified in Table 4.1-1, are not met.

C. The requirements of Specification 3.0.1 are not applicable.

Basis

The Movable In-core Instrumentation System [1] has five drives, five detectors, and 50 thimbles in the core. Each detector can be routed to twenty or more thimbles. Consequently, the full system has a great deal more capability than would be needed for the calibration of the excore detectors.

To calibrate the excore detectors system, it is only necessary that the Movable In-core System be used to determine the gross power distribution in the core as indicated by the power balance between the top and bottom halves of the core.

After the excore system is calibrated initially, recalibration is needed only infrequently to compensate for changes in the core, due for example to fuel depletion, and for changes in the detectors.

If the recalibration is not performed, the mandated power reduction assures safe operation of the reactor since it will compensate for an error of 10% in the excore protection system. Experience at Beznau No. 1 and R. E. Ginna plants has shown that drift due to the core on instrument channels is very slight. Thus limiting the operating levels to 90% of the rated two and three loop powers is very conservative for both operational modes.

Reference

(1) FSAR - Section 7.6

3.20 SHOCK SUPPRESSORS (SNUBBERS)

Applicability

Applies to all shock suppressors (snubbers) which are required to protect the reactor coolant system and other safety-related systems. Snubbers excluded from this inspection program are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effects on any safety-related system.

Objective

To define those limiting conditions for operation that are necessary to ensure that all snubbers required to protect the reactor coolant system, or any other safety-related system or component, are operable during reactor operation.

Specifications

A. During all modes of operation except Cold Shutdown and Refueling, all snubbers required to protect the reactor coolant system and other safety related systems shall be operable except as noted in 3.20.B and 3.20.C below.

B. If any snubber required to protect the reactor coolant system and other safety-related systems is found to be inoperable, it must be repaired and made operable, or otherwise replaced with one which is operable within 72 hours.

C. If the requirements of Specification B cannot be met, an orderly shutdown shall be initiated, and the reactor shall be in the hot shutdown condition within 36 hours.

D. If a snubber is determined to be inoperable while the reactor is in the shutdown or refueling mode, the snubber shall be made operable or replaced prior to reactor startup.

Basis

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all snubbers required to protect the primary coolant system, or any other safety related system or component, be operable during reactor operation.

Because snubber protection is required only during low probability events, a period of 72 hours is allowed for repairs of replacement. In case a shutdown is required, the allowance of 36 hours to reach a hot shutdown condition will permit an orderly shutdown consistent with standard operating procedures. Since plant startup should not commence with knowingly defective safety related equipment, Specification 3.20.D prohibits startup with inoperable snubbers.

3.21 MAIN CONTROL ROOM/EMERGENCY SWITCHGEAR ROOM (MCR/ESGR) EMERGENCY VENTILATION SYSTEM (EVS)

Applicability

The following specifications are applicable whenever either unit is above COLD SHUTDOWN.

Objective

To specify the functional requirements for the MCR/ESGR EVS.

Specifications

A. Two MCR/ESGR EVS trains shall be OPERABLE whenever the unit is above COLD SHUTDOWN.

   Note: The MCR/ESGR envelope boundary may be opened intermittently under administrative control.

B. If one required MCR/ESGR EVS train is inoperable for reasons other than Specification 3.21.C, restore the MCR/ESGR EVS train to OPERABLE status within 7 days.

C. If one or more required MCR/ESGR EVS trains are inoperable due to an inoperable MCR/ESGR envelope boundary, then perform the following:

   1. Immediately initiate action to implement mitigating actions.

   2. Within 24 hours, verify mitigating actions ensure MCR/ESGR envelope occupant exposures to radiological, chemical, and smoke hazards will not exceed limits.

   3. Within 90 days, restore MCR/ESGR envelope boundary to OPERABLE status.

D. If the requirements of Specifications 3.21.B or 3.21.C are not met, the unit shall be placed in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

E. If two required MCR/ESGR EVS trains are inoperable for reasons other than TS 3.21.C, the unit shall be placed in at least HOT SHUTDOWN within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

BASES

BACKGROUND - The MCR/ESGR Emergency Ventilation System (EVS) provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The MCR/ESGR EVS consists of four full capacity trains that supply filtered air to the MCR/ESGR envelope and a MCR/ESGR envelope boundary that limits the inleakage of unfiltered air. Each MCR/ESGR EVS train consists of a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves, dampers, doors, barriers, and instrumentation also form part of the system. One EVS train is capable of performing the safety function of providing outside filtered air for pressurization. Two independently powered EVS trains are required for independence and redundancy.

The MCR/ESGR envelope is the area within the confines of the MCR/ESGR envelope boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the common Main Control Room and the Emergency Switchgear Rooms, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The MCR/ESGR envelope is protected during normal operation, natural events, and accident conditions. The MCR/ESGR envelope boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the MCR/ESGR envelope. The OPERABILITY of the MCR/ESGR envelope boundary must be maintained to ensure that the inleakage of unfiltered air into the MCR/ESGR envelope will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to MCR/ESGR envelope occupants. The MCR/ESGR envelope and its boundary are defined in the MCR/ESGR Envelope Habitability Program (TS 6.4.R).

Upon receipt of the actuating signal(s), normal air supply to and exhaust from the MCR/ESGR envelope is isolated. Two dampers in series in both the MCR/ESGR envelope supply and exhaust ducts close to isolate the MCR/ESGR envelope. Approximately 60 minutes after the isolation of the MCR/ESGR envelope, the MCR/ESGR EVS is manually actuated. Each MCR/ESGR EVS train provides filtered air from the Turbine Building to the MCR/ESGR envelope through HEPA filters and charcoal adsorbers. Prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers.

Pressurization of the MCR/ESGR envelope, although not required by the accident analyses, limits infiltration of unfiltered air from the surrounding areas adjacent to the MCR/ESGR envelope.

A single train of the MCR/ESGR EVS will pressurize the MCR/ESGR envelope to about 0.05 inches water gauge relative to external areas adjacent to the MCR/ESGR envelope boundary. The MCR/ESGR EVS operation in maintaining the MCR/ESGR envelope habitable is discussed in the UFSAR, Section 9.13 (Ref. 3).

Redundant MCR/ESGR EVS supply trains provide pressurization and filtration should one train fail to start or should an excessive pressure drop develop across the operating filter train. Isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. The MCR/ESGR EVS is designed in accordance with Seismic Category I requirements.

The MCR/ESGR EVS is designed to maintain a habitable environment in the MCR/ESGR envelope for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem total effective dose equivalent (TEDE).

APPLICABLE SAFETY ANALYSES - The MCR/ESGR EVS components are arranged in redundant, safety related ventilation trains. The MCR/ESGR EVS provides airborne radiological protection for the MCR/ESGR envelope occupants, as demonstrated by the MCR/ESGR envelope occupant dose analyses for the most limiting design basis accident fission product release presented in the UFSAR, Chapter 14 (Ref. 4).

The MCR/ESGR EVS provides protection from smoke and hazardous chemicals to the MCR/ESGR envelope occupants. An evaluation of hazardous chemical releases demonstrates that the toxicity limits for chemicals are not exceeded in the MCR/ESGR envelope following a hazardous chemical release (Refs. 1 and 5) or that ample time is available for MCR/ESGR envelope occupants to isolate the MCR/ESGR envelope. The evaluation of a smoke challenge demonstrates that it will not result in the inability of the MCR/ESGR envelope occupants to control the reactor either from the MCR or from the remote shutdown panel (Ref. 2).

The worst case single active failure of a component of the MCR/ESGR EVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The MCR/ESGR EVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LIMITING CONDITIONS FOR OPERATION (LCO) - Two independent and redundant MCR/ESGR EVS trains are required to be OPERABLE to ensure that at least one is available to pressurize and to provide filtered air to the MCR/ESGR envelope assuming a single active failure disables one of the two required trains. Due to electrical power considerations, one train must be from the other unit. Total system failure, such as from a loss of both ventilation trains or from an inoperable MCR/ESGR envelope boundary, could result in exceeding a dose of 5 rem TEDE to the MCR/ESGR envelope occupants in the event of a large radioactive release.

Each MCR/ESGR EVS train is considered OPERABLE when the individual components necessary to limit MCR/ESGR envelope occupant exposure are OPERABLE in the two required trains of the MCR/ESGR EVS, one train of which is from the other unit. A MCR/ESGR EVS train is OPERABLE when the associated:

a. Fan is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE, and air flow can be maintained.

In order for the MCR/ESGR EVS trains to be considered OPERABLE, the MCR/ESGR envelope boundary must be maintained such that the MCR/ESGR envelope occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the MCR/ESGR envelope boundary to be opened intermittently under administrative controls. This Note only applies to openings in the MCR/ESGR envelope boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the MCR/ESGR envelope. This individual will have a method to rapidly close the opening and to restore the MCR/ESGR envelope boundary to a condition equivalent to the design condition when a need for MCR/ESGR envelope isolation is indicated.

<u>APPLICABILITY</u> - In REACTOR OPERATION conditions above COLD SHUTDOWN, the MCR/ESGR EVS must be OPERABLE to ensure that the MCR/ESGR envelope will remain habitable during and following a DBA.

<u>ACTIONS</u>

<u>3.21.B</u>

When one required MCR/ESGR EVS train is inoperable, for reasons other than an inoperable MCR/ESGR envelope boundary, action must be taken to restore OPERABLE status within 7 days. In this condition, the remaining required OPERABLE MCR/ESGR EVS train is adequate to perform the MCR/ESGR envelope occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE MCR/ESGR EVS train could result in loss of MCR/ESGR EVS function. The 7 day Allowed Outage Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

3.21.C

If the unfiltered inleakage of potentially contaminated air past the MCR/ESGR envelope boundary and into the MCR/ESGR envelope can result in MCR/ESGR envelope occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of MCR/ESGR envelope occupants from hazardous chemicals or smoke, the MCR/ESGR envelope boundary is inoperable. Actions must be taken to restore an OPERABLE MCR/ESGR envelope boundary within 90 days.

During the period that the MCR/ESGR envelope boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on MCR/ESGR envelope occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that MCR/ESGR envelope occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable MCR/ESGR envelope boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Allowed Outage Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Allowed Outage Time is reasonable based on the determination that the mitigating actions will ensure protection of MCR/ESGR envelope occupants within analyzed limits while limiting the probability that MCR/ESGR envelope occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Allowed Outage Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the MCR/ESGR envelope boundary.

3.21.D

In REACTOR OPERATION conditions above COLD SHUTDOWN, if the inoperable MCR/ESGR EVS train or the MCR/ESGR envelope boundary cannot be restored to OPERABLE status within the Allowed Outage Time, the unit must be placed in a REACTOR OPERATION condition that minimizes accident risk. To achieve this status, the unit must be placed in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours. The allowed completion times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

3.21.E

If both MCR/ESGR EVS trains are inoperable in REACTOR OPERATION conditions above COLD SHUTDOWN for reasons other than an inoperable MCR/ESGR envelope boundary (i.e., TS 3.21.C), the MCR/ESGR EVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, the unit must be placed in at least HOT SHUTDOWN within 6 hours and in COLD SHUTDOWN within the following 30 hours.

REFERENCES

1. UFSAR, Section 2.1, Geography, Demography and Potential External Hazards
2. UFSAR, Section 9.10, Fire Protection
3. UFSAR, Section 9.13, Auxiliary Ventilation Systems
4. UFSAR, Chapter 14, Safety Analysis
5. Letters from B. R. Sylvia (VEPCO) to Harold R. Denton (NRC) dated January 19 and June 30, 1981, Response to Item III.D.3.4, Control Room Habitability Requirements of NUREG-0737 for Surry Power Station
6. Regulatory Guide 1.196, "Control Room Habitability at Light-Water Nuclear Power Reactors"
7. NEI 99-03, "Control Room Habitability Assessment," June 2001
8. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability" (ADAMS Accession No. ML040300694)

3.22 AUXILIARY VENTILATION EXHAUST FILTER TRAINS

Applicability

Applies to the ability of the safety-related system to remove particulate matter and gaseous iodine following a LOCA.

Objective

To specify requirements to ensure the proper function of the system.

Specification

A. Whenever either unit's Reactor Coolant System temperature and pressure is greater than 350°F and 450 psig, respectively, two auxiliary ventilation exhaust filter trains shall be OPERABLE with:

   1. Two filter exhaust fans;

   2. Two HEPA filter and charcoal adsorber assemblies.

B. With one train of the exhaust filter system inoperable for any reason, return the inoperable train to an operable status within 7 days or be in at least Hot Shutdown within the next 6 hours and in Cold Shutdown within the following 48 hours.

Basis

The purpose of the filter trains located in the auxiliary building is to provide standby capability for removal of particulate and iodine contaminants from the exhaust air of the charging pump cubicles of the auxiliary building, fuel building, decontamination building, containment (during shutdown) and safeguards building adjacent to the containment which discharge through the ventilation vent and could require filtering prior to release. During normal plant operation, the exhaust from any one of these areas can be diverted, if required, through the auxiliary building filter trains remotely from the control room. The safeguards building exhaust and the charging pump cubicle exhaust are automatically diverted through the filter trains in the event of a LOCA (diverted on a safety injection system signal). The fuel building exhaust and purge exhaust are not required to be aligned to pass through the filters during spent fuel handling since the Fuel Handling Accident analysis takes no credit for these filters.

High efficiency particulate air (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of the iodine adsorbers. The charcoal adsorbers are installed to reduce the potential release of radioiodine to the environment.

3.23 MAIN CONTROL ROOM AND EMERGENCY SWITCHGEAR ROOM AIR CONDITIONING SYSTEM

Applicability

Applies to the Main Control Room (MCR) and Emergency Switchgear Room (ESGR) Air Conditioning System.

Objective

To specify requirements to ensure the proper function of the Main Control Room and Emergency Switchgear Room Air Conditioning System.

Specification

A. The Main Control Room and Emergency Switchgear Room Air Conditioning System shall be OPERABLE as delineated in the following:

1. Chiller Refrigeration Units

   a. Three main control room and emergency switchgear room chillers must be OPERABLE whenever either unit is above COLD SHUTDOWN.

   b. The three OPERABLE chillers are required to be powered from three of the four emergency buses with one of those chillers capable of being powered from the fourth emergency bus.

   c. If one of the OPERABLE chillers becomes inoperable or is not powered as required by Specification 3.23.A.1.b, return an inoperable chiller to OPERABLE status within seven (7) days or bring both units to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

   d. If two of the OPERABLE chillers become inoperable or are not powered as required by Specification 3.23.A.1.b, return an inoperable chiller to OPERABLE status within one (1) hour or bring both units to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

2. Air Handling Units (AHUs)

   a. Unit 1 air handling units, 1-VS-AC-1, 1-VS-AC-2, 1-VS-AC-6, and 1-VS-AC-7, must be OPERABLE whenever Unit 1 is above COLD SHUTDOWN.

      1. If either any single Unit 1 AHU or two Unit 1 AHUs on the same chilled water loop (1-VS-AC-1 and 1-VS-AC-7 or 1-VS-AC-2 and 1-VS-AC-6) become inoperable, restore operability of the one inoperable AHU or two inoperable AHUs within seven (7) days or bring Unit 1 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

      2. If two Unit 1 AHUs on different chilled water loops and in different air conditioning zones (1-VS-AC-1 and 1-VS-AC-6 or 1-VS-AC-2 and 1-VS-AC-7) become inoperable, restore operability of the two inoperable AHUs within seven (7) days or bring Unit 1 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

      3. If two Unit 1 AHUs in the same air conditioning zone (1-VS-AC-1 and 1-VS-AC-2 or 1-VS-AC-6 and 1-VS-AC-7) become inoperable, restore operability of at least one Unit 1 AHU in each air conditioning zone (1-VS-AC-1 or 1-VS-AC-2 and 1-VS-AC-6 or 1-VS-AC-7) within one (1) hour or bring Unit 1 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

      4. If more than two Unit 1 AHUs become inoperable, restore operability of at least one Unit 1 AHU in each air conditioning zone (1-VS-AC-1 or 1-VS-AC-2 and 1-VS-AC-6 or 1-VS-AC-7) within one (1) hour or bring Unit 1 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

   b. Unit 2 air handling units, 2-VS-AC-8, 2-VS-AC-9, 2-VS-AC-6, and 2-VS-AC-7 must be OPERABLE whenever Unit 2 is above COLD SHUTDOWN.

      1. If either any single Unit 2 AHU or two Unit 2 AHUs on the same chilled water loop (2-VS-AC-7 and 2-VS-AC-9 or 2-VS-AC-6 and 2-VS-AC-8) become inoperable, restore operability of the one inoperable AHU or two inoperable AHUs within seven (7) days or bring Unit 2 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

2. If two Unit 2 AHUs on different chilled water loops and in different air conditioning zones (2-VS-AC-7 and 2-VS-AC-8 or 2-VS-AC-6 and 2-VS-AC-9) become inoperable, restore operability of the two inoperable AHUs within seven (7) days or bring Unit 2 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

3. If two Unit 2 AHUs in the same air conditioning zone (2-VS-AC-8 and 2-VS-AC-9 or 2-VS-AC-6 and 2-VS-AC-7) become inoperable, restore operability of at least one Unit 2 AHU in each air conditioning zone (2-VS-AC-8 or 2-VS-AC-9 and 2-VS-AC-6 or 2-VS-AC-7) within one (1) hour or bring Unit 2 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

4. If more than two Unit 2 AHUs become inoperable, restore operability of at least one Unit 2 AHU in each air conditioning zone (2-VS-AC-8 or 2-VS-AC-9 and 2-VS-AC-6 or 2-VS-AC-7) within one (1) hour or bring Unit 2 to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the following 30 hours.

c. Both Unit 1 AHUs or both Unit 2 AHUs powered from the respective H buses (1-VS-AC-1 and 1-VS-AC-7 or 2-VS-AC-6 and 2-VS-AC-8) must be OPERABLE whenever both units are above COLD SHUTDOWN.

1. If one or two AHUs on each unit powered from an H bus is inoperable, restore operability of the inoperable AHU(s) on one unit within one (1) hour or bring both units to HOT SHUTDOWN within the next six (6) hours and be in COLD SHUTDOWN within the next 30 hours.

Basis

The MCR and ESGR Air Conditioning System (ACS) cools the MCR/ESGR envelope. From an ACS perspective, the envelope consists of four zones: 1) the Unit 1 side of the control room (including the Unit 1 air conditioning equipment and computer rooms), 2) the Unit 2 side of the control room (including the annex area, the Unit 2 air conditioning equipment and computer rooms), 3) the Unit 1 ESGR and relay room (referred to as the Unit 1 ESGR), and 4) the Unit 2 ESGR and relay room (including MER-3), referred to as the Unit 2 ESGR. The design basis of the MCR and ESGR ACS is to maintain the MCR/ESGR envelope temperature within the equipment design limits for 30 days of continuous occupancy after a design basis accident (DBA). The ACS includes five chillers (1-VS-E-4A, 4B, 4C, 4D, and 4E). Chillers 4A, 4B, and 4C are located in MER-3, in the Unit 2 ESGR. Chillers 4D and 4E are located in MER-5, in the Unit 2 Turbine Building. The chillers supply chilled water to eight air handling units (AHUs), arranged in two independent and redundant chilled water loops. Each chilled water loop provides redundant 100% heat removal capacity per unit. Each loop contains four AHUs (one AHU in each unit's air conditioning zones), the necessary power supplies, the associated valves, piping (from the supply header to return header), instrumentation, and controls. Each AHU has 100% capacity for cooling its zone.

The combination of five chillers and two chilled water loops affords considerable flexibility in meeting the cooling requirements. Two chillers are powered from single emergency buses (1-VS-E-4C from 2H, 1-VS-E-4E from 1H). The remaining three chillers can be powered from either of two emergency buses (1-VS-E-4A from 1J or 2J, 1-VS-E-4B from 1J or 2H, and 1-VS-E-4D from 1H or 2J). The AHUs are powered from the four emergency buses in pairs. For example, the Unit 1 MCR and ESGR AHUs 1-VS-AC-1 and 1-VS-AC-7 are powered from the 1H bus; the redundant Unit 1 MCR and ESGR AHUs 1-VS-AC-2 and 1-VS-AC-6 are powered from the 1J bus. Control of the ACS is by manual action.

The chillers are procedurally aligned by power supply to meet TS 3.23.A.1.b, and the AHU pairs are normally aligned to match the power supplies of the OPERABLE chillers. For example, chiller 1-VS-E-4E and AHUs 1-VS-AC-1 and 1-VS-AC-7 are powered from the 1H emergency bus. However, due to the number of emergency diesel generators (EDGs) and the chiller/AHU piping layout, only one chiller and AHU pair can be powered from each emergency bus at a time. Also, if chilled water is needed in both chilled water loops, two chillers must be operated. Only one chiller can be operated on each chilled water loop at a time, and the 4D and 4E chillers cannot be operated simultaneously. The combinations of OPERABLE chillers/AHUs allowed by procedure ensure that sufficient cooling capacity is available during a DBA with a coincident loss of offsite power (LOOP) and single failure of an EDG, a chiller, or an AHU.

Acceptable operating alignments include one chiller supplying one chilled water loop with four operating AHUs, or two chillers supplying two chilled water loops with two AHUs operating on each loop. In either case, one AHU must be operated in the MCR and ESGR air conditioning zones of each unit. During normal operation, and accident scenarios with a LOOP and single failure of an EDG, one chiller providing chilled water to one chilled water loop with four operating AHUs is sufficient to maintain the MCR and ESGR air temperature within normal limits. In the event of a DBA with all mitigation equipment operating (i.e., higher heat loads due to offsite power available and no single failures), two chillers and two chilled water loops, with one operating AHU in each unit's MCR and ESGR, are necessary to maintain temperatures within normal limits; with one chiller, one chilled water loop, and four operating AHUs, temperatures will be maintained within the equipment design limits.

The MCR and ESGR ACS is considered to be OPERABLE when the individual components necessary to cool the MCR and ESGR envelope are OPERABLE. The operability requirements for the chillers and AHUs are separate but interdependent. The required chillers are considered OPERABLE when required chilled water and service water flowpaths, required power supplies, and controls are OPERABLE. A chiller does not have to be in operation to be considered OPERABLE. An AHU is OPERABLE when the associated chilled water flowpath, fan, motor, dampers, as well as associated ductwork and controls, are OPERABLE.

The Technical Specifications require the operability of the ACS components. Due to the redundancy and diversity of components, the inoperability of one active component does not render the ACS incapable of performing its function. This allows increased flexibility in unit operations under circumstances when more than one ACS component is inoperable. Similarly, the inoperability of two different components, each in a different loop or powered from a different power supply, does not necessarily result in a loss of function for the ACS. However, due to the emergency power design (three EDGs and four emergency buses), realignment of the swing or shared EDG is required in certain instances of inoperable AHUs and is directed by procedure.

The requirements and action statements for the AHUs powered from an H emergency bus eliminate the potential for complex operator actions in certain instances of two inoperable AHUs. The swing EDG can supply either J bus, but not both. With an AHU powered from the H bus inoperable on each unit, a DBA with a LOOP and no single failure would result in one air conditioning zone with no AHU available. In this case, in order to ensure power is available to an AHU in each air conditioning zone, operators would have to procedurally realign the swing diesel and cross-connect emergency buses. By prohibiting the simultaneous inoperability of an H-bus powered AHU on each unit, cross-connect of the emergency buses will not be necessary. Realignment of the swing diesel is still required, and procedures direct the operators to realign the swing EDG (from the MCR) as necessary to ensure that there is an operating AHU in the MCR and ESGR air conditioning zones of each unit.

The exterior surface of the MCR and ESGR ACS chilled water piping located in the ESGR, the MCR, and MER-3 is exhibiting general corrosion. For the purpose of replacing the MCR and ESGR ACS chilled water piping, temporary 45-day and 14-day allowed outage times (AOTs) are provided, as discussed in the footnote to Technical Specifications 3.23.C.2.a.1 and 3.23.C.2.b.1. The basis for and the risk evaluation of the temporary AOTs, as well as equipment unavailability restrictions and compensatory actions, are provided in the licensee's submittal dated February 26, 2007 (Serial No. 07-0109). Four entries into the temporary AOTs are permitted in a 24-month time span. The 24-month time frame begins upon entry into the first temporary AOT. The four entries accommodate replacement of 1) the chilled water loop C piping in the ESGR and the MCR (45-day AOT), 2) the chilled water loop A piping in the ESGR and the MCR (45-day AOT), 3) the chilled water piping in MER-3 associated with chiller 1-VS-E-4A (14-day AOT), and 4) the chilled water piping in MER-3 associated with chiller 1-VS-E-4C (14-day AOT). Each AOT extension shall be limited to a one-time use which ends when the affected MCR and ESGR ACS components are returned to OPERABLE status. Concurrent use of more than one allowed outage time extension is not permitted. Upon completion of the work associated with the fourth temporary AOT, the footnote is no longer applicable.

4.0 SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements (SRs) shall be met during the REACTOR OPERATION conditions or other specified conditions in the individual Limiting Conditions for Operation (LCO), unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified frequency shall be failure to meet the LCO except as provided in SR 4.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

4.0.2 Surveillance requirement specified time intervals may be adjusted plus or minus 25 percent to accommodate normal test schedules.

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

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable action(s) must be taken.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable action(s) must be taken.

4.0.4 Entry into an operational condition shall not be made unless the surveillance requirement(s) associated with a Limiting Condition of Operation has been performed within the stated surveillance interval or as otherwise specified. This provision shall not prevent passage through or to operational conditions as required to comply with Action Statement requirements.

BASES

4.0.1 Surveillance Requirement (SR) 4.0.1 establishes the requirement that SRs must be met during the REACTOR OPERATION conditions or other specified conditions in the individual Limiting Conditions for Operation (LCO) that apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the operability of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified frequency, in accordance with SR 4.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified frequency.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a REACTOR OPERATION condition or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given REACTOR OPERATION condition or other specified condition.

Surveillances, including Surveillances invoked by Action Statements, do not have to be performed on inoperable equipment because the Action Statements define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 4.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 4.0.2. Post maintenance testing may not be possible in the current REACTOR OPERATION condition or other specified conditions in the individual LCO due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a REACTOR OPERATION condition or other specified condition where other necessary post maintenance tests can be completed.

An example of this process is Auxiliary Feedwater (AFW) pump turbine maintenance during refueling that requires testing at steam pressures that cannot be obtained until the unit is at HOT SHUTDOWN conditions. However, if other appropriate testing is satisfactorily completed, the AFW System can be considered OPERABLE. This allows startup and other necessary testing to proceed until the plant reaches the steam pressure required to perform the testing.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance value and permits the performance of more frequent surveillance activities.

4.0.3 SR 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 4.0.2, and not at the time that the specified Surveillance frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with the Action Statement(s) or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering POWER OPERATION after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 4.0.3 allows for the full delay period of up to the specified frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 4.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of REACTOR OPERATION condition changes imposed by Action Statements.

Failure to comply with the specified frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Allowed Outage Time(s) of the Action Statement(s) for the applicable LCO conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Allowed Outage Time(s) of the Action Statement(s) for the applicable LCO conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Allowed Outage Time(s) of the Action Statement(s), restores compliance with SR 4.0.1.

4.0.4 This specification establishes the requirement that all applicable surveillances must be met before entry into an operational condition specified in the applicability statement. The purpose of this specification is to ensure that system and component operability requirements or parameter limits are met before entry into a condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in operational conditions associated with plant shutdown as well as startup.

Under the provisions of this specification, the applicable surveillance requirements must be performed within the specified surveillance interval to ensure that the Limiting Conditions for Operation are met during initial plant startup or following a plant outage.

Exceptions to Specification 4.0.4 allow performance of surveillance requirements associated with a Limiting Condition for Operation after entry into the applicable operational condition.

When a shutdown is required to comply with Action Statement requirements, the provisions of Specification 4.0.4 do not apply because this would delay placing the facility in a lower condition of operation.

4.1 OPERATIONAL SAFETY REVIEW

Applicability

Applies to items directly related to safety limits and limiting conditions for operation.

Objective

To specify the minimum frequency and type of surveillance to be applied to unit equipment and conditions.

Specification

A. Calibration, testing, and checking of instrumentation channels and interlocks shall be performed as detailed in Tables 4.1-1, 4.1-1A, and 4.1-2 and at the frequencies specified in the Surveillance Frequency Control Program, unless otherwise noted in the Tables.

B. Equipment tests shall be performed as detailed in Table 4.1-2A and at the frequencies specified in the Surveillance Frequency Control Program, unless otherwise noted in the Tables and as detailed below.

1. In addition to the requirements of the Inservice Testing Program, each Pressurizer PORV and block valve shall be demonstrated OPERABLE at the frequencies specified in the Surveillance Frequency Control Program by:

    a. Performing a complete cycle of each PORV with the reactor coolant average temperature >350°F.

    b. Performing a complete cycle of the solenoid air control valve and check valves on the air accumulators in the PORV control system.

    c. Operating each block valve through one complete cycle of travel. This surveillance is not required if the block valve is closed in accordance with 3.1.6.a, b, or c.

    d. Verifying that the pressure in the PORV backup air supply is greater than the surveillance limit.

    e. Performing functional testing and calibration of the PORV backup air supply instrumentation and alarm setpoints.

2. The pressurizer water volume shall be determined to be within its limit as defined in Specification 2.3.A.3.a at least once per 12 hours whenever the reactor is not subcritical by at least 1% $\Delta k/k$.

3. Each Reactor Vessel Head vent path remote operating isolation valve not required to be closed by Specification 3.1.A.7a or 3.1.A.7b shall be demonstrated OPERABLE at each COLD SHUTDOWN but not more often than once per 92 days by operating the valve through one complete cycle of full travel from the control room.

4. Each Reactor Vessel Head vent path shall be demonstrated OPERABLE following each refueling by:

   a. Verifying the manual isolation valves in each vent path are locked in the open position.

   b. Cycling each remote operating isolation valve through at least one complete cycle of full travel from the control room.

   c. Verifying flow through the reactor vessel head vent system vent paths.

C. Sampling tests shall be conducted as detailed in Table 4.1-2B and at the frequencies specified in the Surveillance Frequency Control Program, unless otherwise noted in the Table.

D. Whenever containment integrity is not required, only the asterisked items in Table 4.1-1 and 4.1-2A and 4.1-2B are applicable.

E. Flushing of wetted sensitized statinless steel pipe sections as identified in the Basis Section shall be conducted only if the RWST Water Chemistry exceeds 0.15 PPM chlorides and/or fluorides (CL^- and or F^-). Flushing of sensitized stainless steel pipe sections shall be conducted as detailed in TS Table 4.1-3A and 4.1-3B.

F. Containment Ventilation Purge System isolation valves:

1. The outside Containment Ventilation Purge System isolation valves and the isolation valve in the containment vacuum ejector suction line outside containment shall be determined locked, sealed, or otherwise secured in the closed position at the frequency specified in the Surveillance Frequency Control Program.

2. The inside Containment Ventilation Purge System isolation valves and the isolation valve in the containment vacuum ejector suction line inside containment shall be verified locked, sealed, or otherwise secured in the closed position each COLD SHUTDOWN, but not required to be verified more than once per 92 days.

G. Verify that each containment penetration not capable of being closed by OPERABLE automatic isolation valves and required to be closed during accident conditions is closed by manual valves, blind flanges, or deactivated automatic valves secured* in the closed position at the frequency specified in the Surveillance Frequency Control Program. Valves, blind flanges, and deactivated automatic or manual valves located inside containment which are locked, sealed, or otherwise secured in the closed position shall be verified closed during each COLD SHUTDOWN, but not required to be verified more than once per 92 days.

* Non-automatic or deactivated automatic valves may be opened on an intermittent basis under administrative control. The valves identified in TS 3.8.A.2 and TS 3.8.A.3 are excluded from this provision.

H. If the RWST Water Chemistry exceeds 0.15 PPM for Cl^- and/or F^-, flushing of sensitized stainless steel piping as required by 4.1.E will be performed once the RWST Water Chemistry has been brought within specification limit of less than 0.15 PPM chlorides and/or fluorides. Samples will be taken periodically until the sample indicates the Cl^- and/or F^- and levels are below 0.15 PPM.

BASIS

Check

Failures such as blown instrument fuses, defective indicators, and faulted amplifiers which result in "upscale" or "downscale" indication can be easily recognized by simple observation of the functioning of an instrument or system. Furthermore, such failures are, in many cases, revealed by alarm or annunciator action, and a periodic check supplements this type of built-in surveillance.

Calibration

Calibration shall be performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (power level) channels shall be calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process systems instrumentation errors resulting from drift within the individual instruments are normally negligible.

During the interval between periodic channel tests and check of each channel, a comparison between redundant channels will reveal any abnormal condition resulting from a calibration shift, due to instrument drift of a single channel.

During the periodic channel test, if it is deemed necessary, the channel may be tuned to compensate for the calibration shift. However, it is not expected that this will be required at any fixed or frequent interval.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Testing

The OPERABILITY of the Reactor Trip System and ESFAS instrumentation systems and interlocks ensures that 1) the associated ESF action and/or reactor trip will be initiated when the parameter monitored by each channel or combination thereof exceeds its setpoint, 2) the specified coincidence logic and sufficient redundancy are maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the RTS and ESFAS instrumentation, and 3) sufficient system functional capability is available from diverse parameters.

The surveillance requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance test frequencies are controlled under the Surveillance Frequency Control Program.

Surveillance testing of instrument channels is routinely performed with the channel in the tripped condition. Only those instrument channels with hardware permanently installed that permits bypassing without lifting a lead or installing a jumper are routinely tested in the bypass condition. However, an inoperable channel may be bypassed by lifting a lead or installing a jumper to permit surveillance testing of another instrument channel of the same functional unit.

Some items in Table 4.1-1 have a test frequency of prior to each startup if not done within the previous 31 days with no applicability specified with respect to when during each startup. The following information is provided for those items to clarify when during each startup the testing is required to be performed:

- Table 4.1-1 Item 2 - Nuclear Intermediate Range - Prior to criticality if not done within the previous 31 days
- Table 4.1-1 Item 3 - Nuclear Source Range - Prior to criticality if not done within the previous 31 days
- Table 4.1-1 Item 28.A - Turbine Trip Stop Valve Closure - Prior to exceeding the P-7 setpoint if not done within the previous 31 days
- Table 4.1-1 Item 28.B - Turbine Trip Low Fluid Oil Pressure - Prior to exceeding the P-7 setpoint if not done within the previous 31 days

Flushing

During construction of the facility, stress relieving of some of the cold bent stainless steel piping resulted in the piping becoming sensitized to potential stress corrosion cracking under certain conditions, e.g. low pH in conjunction with high chlorides. The subsystems containing the sensitized piping were identified in Stone & Webster Report SW-MER-1A dated July 6, 1971 and further evaluated in Virginia Power Technical Report ME-0009, Rev. 1, dated December 9, 1987. The sensitized piping was either not wetted, reheat treated, or is justified as acceptable because it is in a wetted system with adequate chemistry control i.e., chlorides and/or fluorides (Cl^- and/or F^-) less than 0.15 ppm. These subsystems are as follows:

	Subsystem	Remarks
1)	Recirc. spray inside containment	Not Wetted
2)	Recirc. spray outside containment	Not Wetted
3)	Containment spray inside containment	Not Wetted
4)	Containment spray outside containment	Wetted
5)	Low hd. SI pump discharge	Wetted
6)	Low hd. SI pump to 1st iso. valve	Wetted
7)	High hd. SI inside containment	Wetted
8)	High hd. SI pump discharge	Wetted
9)	RHR	Wetted
10)	Charging and letdown system in containment	Flowing System
11)	Pressurizer relief lines	Reheat Treated Prior to Operation
12)	Pressurizer spray & surge lines	Flowing System

The sensitized piping found in a wetted system is acceptable as long as the fluid in or passing through the piping is less than 0.15 PPM Cl^- and/or F^-. The wetted systems are supplied from the RWST with the exception of the RHR system which communicates directly with the RCS during plant shutdowns. The RHR system does not communicate with the RWST during power operations and therefore, does not require flushing if Cl^- and/or F^- concentration exceeds 0.15 ppm. The acceptance criteria for the piping are based on the RWST Water chemistry staying below 0.15 PPM chlorides and/or fluorides. If the RWST chemistry on chlorides and/or fluorides is out of specification the sensitized piping that is normally supplied by the RWST will be flushed per tables 4.1-3A and 4.1-3B for Units 1 and 2 respectively. Each refueling outage the wetted systems are flow tested, or put in service which will flush the strategic portions of those systems.

The refueling water storage tank is sampled weekly for Cl^- and/or F^- contaminations. Weekly sampling is adequate to detect any inleakage of contaminated water.

Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Isolation Actuation Instrumentation

The MCR/ESGR Envelope Isolation Actuation function provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity. A functional check of the Manual Actuation function is performed at the frequency specified in the Surveillance Frequency Control Program. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Requirement will ensure that the two trains of the MCR/ESGR envelope isolation dampers close upon manual actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation and that the supply and exhaust fans in the normal ventilation system for the MCR/ESGR envelope shut down, as well as adjacent area ventilation fans. Automatic actuation of the MCR/ESGR Envelope Isolation Actuation Instrumentation is confirmed as part of the Logic Channel Testing for the Safety Injection system.

Pressurizer PORV, PORV Block Valve, and PORV Backup Air Supply

The safety-related, seismic PORV backup air supply is relied upon for two functions - mitigation of a design basis steam generator tube rupture accident and low temperature overpressure protection (LTOP) of the reactor vessel during startup and shutdown. The surveillance criteria are based upon the more limiting requirements for the backup air supply (i.e. more PORV cycles potentially required to perform the mitigation function), which are associated with the LTOP function.

The PORV backup air supply system is provided with a calibrated alarm for low air pressure. The alarm is located in the control room. Failures such as regulator drift and air leaks which result in low pressure can be easily recognized by alarm or annunciator action. A periodic verification of air pressure against the surveillance limit supplements this type of built-in surveillance. Based on experience in operation, the minimum checking frequencies set forth are deemed adequate.

RCS Flow

This surveillance requirement in Table 4.1-2A is modified by a note that allows entry into POWER OPERATION, without having performed the surveillance, and placement of the unit in the best condition for performing the surveillance. The note states that the surveillance requirement is not required to be performed until 7 days after reaching a THERMAL POWER of ≥ 90% of RATED POWER (i.e., shall be performed within 7 days after reaching 90% of RATED POWER). [Reference: NRC Safety Evaluation for License Amendments 270/269, issued October 19, 2010] The 7 day period after reaching 90% of RATED POWER is reasonable to establish stable operating conditions, install the test equipment, perform the test, and analyze the results. If reactor power is reduced below 90% of RATED POWER before completion of the RCS flow surveillance, the 7 day period shall be exited, and a separate 7 day period shall be entered when the required condition of reaching 90% of RATED POWER is subsequently achieved. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS Table 4.1-2B

Item 1 - RCS Coolant Liquid Samples

DOSE EQUIVALENT I-131 - This surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The SFCP 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spike initiation; samples at other times would provide inaccurate results.

DOSE EQUIVALENT XE-133 - This surveillance requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days per the SFCP. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken or equivalent sampling method. This surveillance provides an indication of any increase in the noble gas specific activity.

Trending the results of this surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The SFCP 7 day Frequency considers the low probability of a gross fuel failure during this time.

Due to the inherent difficulty in detecting Kr-85 in a reactor coolant sample due to masking from radioisotopes with similar decay energies, such as F-18 and I-134, it is acceptable to include the minimum detectable activity for Kr-85 in this calculation. If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 is not detected, it should be assumed to be present at the minimum detectable activity.

TABLE 4.1-1

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test		Remarks
1.	Nuclear Power Range	SFCP	SFCP (1,5) SFCP (3,5) SFCP(4)	SFCP (2)	1) 2) 3) 4) 5)	Against a heat balance standard, above 15% RATED POWER Signal at ΔT; bistable action (permissive, rod stop, trip) Upper and lower chambers for symmetric offset by means of the movable incore detector system Neutron detectors may be excluded from CHANNEL CALIBRATION The provisions of Specification 4.0.4 are not applicable
2.	Nuclear Intermediate Range (below P-10 setpoint)	*SFCP	SFCP (2,3)	P(1)	1) 2) 3)	Log level; bistable action (permissive, rod stop, trip) Neutron detectors may be excluded from CHANNEL CALIBRATION The provisions of Specification 4.0.4 are not applicable
3.	Nuclear Source Range (below P-6 setpoint)	*SFCP	SFCP (2,3)	P(1)	1) 2) 3)	Bistable action (alarm, trip) Neutron detectors may be excluded from CHANNEL CALIBRATION The provisions of Specification 4.0.4 are not applicable
4.	Reactor Coolant Temperature	*SFCP	SFCP	SFCP (1) SFCP (2)	1) 2)	Overtemperature ΔT Overpower ΔT
5.	Reactor Coolant Flow	SFCP	SFCP	SFCP		
6.	Pressurizer Water Level	SFCP	SFCP	SFCP		
7.	Pressurizer Pressure (High & Low)	SFCP	SFCP	SFCP		
8.	4 KV Voltage and Frequency	N.A.	SFCP	SFCP (1)	1)	Setpoint verification not required
9.	Analog Rod Position	*SFCP (1,2) (3)	SFCP	N.A.	1) 2) 3)	With step counters Each six inches of rod motion when data logger is out of service N.A. when reactor is in HOT, INTERMEDIATE OR COLD SHUTDOWN

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
10.	Rod Position Bank Counters	SFCP (1,2) SFCP (3)	N.A.	N.A.	1) Each six inches of rod motion when data logger is out of service 2) With analog rod position 3) For the control banks, the benchboard indicators shall be checked against the output of the bank overlap unit.
11.	Steam Generator Level	SFCP	SFCP	SFCP	
12.	Deleted				
13.	Deleted				
14.	Deleted				
15.	Recirculation Mode Transfer				
	a. Refueling Water Storage Tank Level-Low-Low	SFCP	SFCP	SFCP	
	b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	SFCP	
16.	Recirculation Spray Pump Start				
	a. RWST Level-Low	SFCP	SFCP	SFCP	
17.	Reactor Containment Pressure-CLS	*SFCP	SFCP	SFCP (1)	1) Isolation valve signal and spray signal
18.	Deleted				
19.	Deleted				
20.	Deleted				
21.	Deleted				
22.	Steam Line Pressure	SFCP	SFCP	SFCP	

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
23.	Turbine First Stage Pressure	SFCP	SFCP	SFCP	
24.	Deleted				
25.	Deleted				
26.	Logic Channel Testing	N.A.	N.A.	SFCP (1)(2)	1) Reactor protection, safety injection and the consequence limiting safeguards system logic are tested per this line item. 2) The master and slave relays are not included in the periodic logic channel test of the safety injection system.
27.	Deleted				
28.	Turbine Trip				Setpoint verification is not applicable
	a. Stop valve closure	N.A.	N.A.	P	
	b. Low fluid oil pressure	N.A.	N.A.	P	
29.	Deleted				
30.	Reactor Trip Breaker	N.A.	N.A.	SFCP	The test shall independently verify operability of the undervoltage and shunt trip attachments
31.	Deleted				

TABLE 4.1-1 (Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
32. Auxiliary Feedwater				
a. Steam Generator Water Level Low-Low	SFCP	SFCP	SFCP (1)	1) The auto start of the turbine driven pump is not included in the periodic test, but is tested within 31 days prior to each startup.
b. RCP Undervoltage	SFCP	SFCP	SFCP (1)(2)	1) The actuation logic and relays are tested within 31 days prior to each startup. 2) Setpoint verification not required.
c. S.I.	(All Safety Injection surveillance requirements)			
d. Station Blackout	N.A.	SFCP	N.A.	
e. Main Feedwater Pump Trip	N.A.	N.A.	SFCP	
33. Loss of Power				
a. 4.16 KV Emergency Bus Undervoltage (Loss of Voltage)	N.A.	SFCP	SFCP (1)	1) Setpoint verification not required.
b. 4.16 KV Emergency Bus Undervoltage (Degraded Voltage)	N.A.	SFCP	SFCP (1)	1) Setpoint verification not required.
c. 4.16 KV Emergency Bus Negative Sequence Voltage (Open Phase)	N.A	SFCP	SFCP (1)	1) Setpoint verification not required.
34. Deleted				
35. Manual Reactor Trip	N.A.	N.A.	SFCP	The test shall independently verify the operability of the undervoltage and shunt trip attachments for the manual reactor trip function. The test shall also verify the operability of the bypass breaker trip circuit.
36. Reactor Trip Bypass Breaker	N.A.	N.A.	SFCP (1), SFCP (2)	1) Remote manual undervoltage trip immediately after placing the bypass breaker into service, but prior to commencing reactor trip system testing or required maintenance. 2) Automatic undervoltage trip.

TABLE 4.1-1 (Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
37. Safety Injection Input to RPS	N.A.	N.A.	SFCP	
38. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	SFCP	
39. Steam/Feedwater Flow and Low S/G Water Level	SFCP	SFCP	SFCP (1)	1) The provisions of Specification 4.0.4 are not applicable
40. Intake Canal Low (See Note 1)	SFCP	SFCP	SFCP (1), SFCP (2)	1) Logic Test 2) Channel Electronics Test
41. Turbine Trip and Feedwater Isolation				
a. Steam generator water level high	SFCP	SFCP	SFCP	
b. Automatic actuation logic and actuation relay	N.A.	SFCP	SFCP (1)	1) Automatic actuation logic only, actuation relays tested each refueling
42. Reactor Trip System Interlocks				
a. Intermediate range neutron flux, P-6	N.A.	SFCP (1)	SFCP (2)	1) Neutron detectors may be excluded from the calibration
b. Low reactor trips block, P-7	N.A.	SFCP (1)	SFCP (2)	2) The provisions of Specification 4.0.4 are not applicable.
c. Power range neutron flux, P-8	N.A.	SFCP (1)	SFCP (2)	
d. Power range neutron flux, P-10	N.A.	SFCP (1)	SFCP (2)	
e. Turbine impulse pressure	N.A.	SFCP	SFCP	

TABLE 4.1-1(Continued)

MINIMUM FREQUENCIES FOR CHECK, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
43. Engineered Safeguards Actuation Interlocks				
a. Reactor trip, P-4	N.A.	N.A.	SFCP	
b. Pressurizer pressure, P-11	N.A.	SFCP	SFCP	
c. Low, low T_{avg}, P-12	N.A.	SFCP	SFCP	

P - Prior to each startup if not done within the frequency specified in the Surveillance Frequency Control Program

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

Note 1:

Check — Consists of verifying for an indicated intake canal level greater than 23'-5.85" that all four low level sensor channel alarms are not in an alarm state.

Calibration — Consists of uncovering the level sensor and measuring the time response and voltage signals for the immersed and dry conditions. It also verifies the proper action of instrument channel from sensor to electronics to channel output relays and annunciator. Only the two available sensors on the shutdown unit would be tested.

Tests —
1) The logic test verifies the three out of four logic development for each train by using the channel test switches for that train.
2) Channel electronics test verifies that electronics module responds properly to a superimposed differential millivolt signal which is equivalent to the sensor detecting a "dry" condition.

TABLE 4.1-A

REACTOR TRIP SYSTEM AND ENGINEERED SAFEGUARDS ACTION INTERLOCKS

DESIGNATION	CONDITION	FUNCTION
Reactor Trip (P-4)	1 of 2 breakers open	Reactor tripped - actuates turbine trip, allows auto closing of main feedwater valves on T_{avg} below setpoint, prevents the opening of the main feedwater valves which were closed by a safety injection or high steam generator water level signal.
Intermediate Range Neutron Flux (P-6)	1 of 2 Intermediate range above setpoint (increasing power level)	Allows manual block of source range reactor trip.
	2 of 2 Intermediate range below setpoint (decreasing power level)	Automatically defeats the block of source range reactor trip.
Power Range Neutron Flux (P-10)	2 of 4 Power range above setpoint (increasing power level)	Allows manual block of power range (low setpoint) and intermediate range reactor trips and intermediate range rod stop. Automatically blocks source range reactor trip.
	3 of 4 Power range below setpoint (decreasing power level)	Automatically defeats the block of power range (low setpoint) and intermediate range reactor trips and intermediate range rod stop.
		Input to P-7.
Low Power Reactor Trip Block (P-7)	2 of 4 Power range above setpoint or 1 of 2 Turbine Impulse chamber above setpoint (Power level increasing)	Allows reactor trip on: Low flow or reactor coolant pump breakers open in more than one loop, Undervoltage (RCP busses), Underfrequency (RCP busses), Turbine Trip, Pressurizer low pressure, and Pressurizer high level.
	3 of 4 Power range below setpoint and 2 of 2 Turbine Impulse chamber pressure below setpoint (Power level decreasing)	Prevents reactor trip on: Low flow or reactor coolant pump breakers open in more than one loop, Undervoltage (RCP busses), Underfrequency (RCP busses), Turbine Trip, Pressurizer low pressure, and Pressurizer high level.

TABLE 4.1-A (continued)

REACTOR TRIP SYSTEM AND ENGINEERED SAFEGUARDS ACTION INTERLOCKS

DESIGNATION	CONDITION	FUNCTION
Power Range Neutron Flux (P-8)	2 of 4 Power range above setpoint (Power level increasing)	Permit reactor trip on low flow or reactor coolant pump breaker open in a single loop.
	3 of 4 Power range below setpoint (Power level decreasing)	Blocks reactor trip on low flow or reactor coolant pump breaker open in a single loop.
Pressurizer Pressure (P-11)	2 of 3 Pressurizer pressure above setpoint (increasing pressure)	On increasing pressurizer pressure, P-11 automatically reinstates safety injection actuation on low pressurizer pressure.
	2 of 3 Pressurizer pressure below setpoint (decreasing pressure)	On decreasing pressure, P-11 allows the manual block of safety injection actuation on low pressurizer pressure.
Low, Low T_{avg} (P-12)	2 of 3 T_{avg} above setpoint (temperature increasing)	On increasing primary coolant loop temperature, P-12 automatically reinstates safety injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure, and provides an arming signal to the steam dump system.
	2 of 3 T_{avg} below setpoint (temperature decreasing)	On decreasing primary coolant loop temperature, P-12 allows the manual block of safety injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure and automatically removes the arming signal from the steam dump system.

TABLE 4.1-1A

EXPLOSIVE GAS MONITORING INSTRUMENTATION REQUIREMENTS

CHANNEL DESCRIPTION	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Waste Gas Holdup System Explosive Gas Monitoring System			
Oxygen Monitor	SFCP	SFCP (1)	SFCP

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

(1) The channel calibration shall include the use of standard gas samples containing a nominal:

1. one volume percent oxygen, balance nitrogen, and

2. four volume percent oxygen, balance nitrogen

TABLE 4.1-2

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

	INSTRUMENT	CHANNEL CHECK (1)	CHANNEL CALIBRATION
1.	Auxiliary Feedwater Flow	SFCP	SFCP
2.	Inadequate Core Cooling	SFCP	SFCP
3.	Containment Pressure (Wide Range)	SFCP	SFCP
4.	Containment Pressure	SFCP	SFCP
5.	Containment Sump Water Level (Wide Range)	SFCP	SFCP
6.	Containment Area Radiation (High Range)	SFCP	SFCP
7.	Power Range Neutron Flux	SFCP	SFCP (2)
8.	Source Range Neutron Flux	SFCP	SFCP (2)
9.	Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range)	SFCP	SFCP
10.	RCS Cold Leg Temperature (Wide Range)	SFCP	SFCP
11.	RCS Pressure (Wide Range)	SFCP	SFCP
12.	Penetration Flow Path Containment Isolation Valve Position	SFCP	SFCP (3)
13.	Pressurizer Level	SFCP	SFCP
14.	Steam Generator (SG) Water Level (Wide Range)	SFCP	SFCP
15.	SG Water Level (Narrow Range)	SFCP	SFCP
16.	SG Pressure	SFCP	SFCP
17.	Emergency Condensate Storage Tank Level	SFCP	SFCP
18.	High Head Safety Injection Flow to Cold Leg	SFCP	SFCP

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

(1) Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.

(2) Neutron detectors are excluded from CHANNEL CALIBRATION.

(3) Rather than CHANNEL CALIBRATION, this surveillance shall be an operational test, consisting of verification of operability of all devices in the channel.

TABLE 4.1-2A

MINIMUM FREQUENCY FOR EQUIPMENT TESTS

	DESCRIPTION	TEST	FREQUENCY	FSAR SECTION REFERENCE
1.	Control Rod Assemblies	Rod drop times of all full length rods at hot conditions	Prior to reactor criticality: a. For all rods following each removal of the reactor vessel head b. For specially affected individual rods following any maintenance on or modification to the control rod drive system which could affect the drop time of those specific rods c. SFCP	7
2.	Control Rod Assemblies	Partial movement of all rods	SFCP	7
3.	Deleted			
4.	Pressurizer Safety Valves	Setpoint	Per the Inservice Testing Program	4
5.	Main Steam Safety Valves	Setpoint	Per the Inservice Testing Program	10
6.	Containment Isolation Trip	* Functional	SFCP	5
7.	Refueling System Interlocks	* Functional	Prior to refueling	9.12
8.	Service Water System	* Functional	SFCP	9.9
9.	Residual Heat Removal System	Functional	Per the Inservice Testing Program	9.3
10.	Deleted			
11.	Diesel Fuel Supply	* Fuel Inventory	SFCP	8.5
12.	Deleted			
13.	Main Steam Line Trip Valves	Functional (Full Closure)	Before each startup (TS 4.7) The provisions of Specification 4.0.4. are not applicable	10

TABLE 4.1-2A (CONTINUED)
MINIMUM FREQUENCY FOR EQUIPMENT TESTS

	DESCRIPTION	TEST	FREQUENCY	FSAR SECTION REFERENCE
14a.	Service Water System Valves in Line Supplying Recirculation Spray Heat Exchangers	Functional	SFCP	9.9
b.	Service Water System Valves Isolating Flow to Non-essential loads on Intake Canal Low Level Isolation	Functional	SFCP	9.9
15.	MCR/ESGR Envelope Isolation Actuation Instrumentation - Manual	Functional	SFCP	9.13
16.	Reactor Vessel Overpressure Mitigating System (except backup air supply)	Functional & Setpoint	Prior to decreasing RCS temperature below 350°F and monthly while the RCS is < 350°F and the Reactor Vessel Head is bolted	4.3
		CHANNEL CALIBRATION	SFCP	
17.	Reactor Vessel Overpressure Mitigating System Backup Air Supply	Setpoint	SFCP	4.3
18.	Power-Operated Relief Valve Control System	Functional, excluding valve actuation	SFCP	4.3
		CHANNEL CALIBRATION	SFCP	

TABLE 4.1-2A(CONTINUED)
MINIMUM FREQUENCY FOR EQUIPMENT TESTS

	DESCRIPTION	TEST	FREQUENCY	UFSAR SECTION REFERENCE
19.	Primary Coolant System	Functional	1. Periodic leakage testing(a)(b) on each valve listed in Specification 3.1.C.5.a shall be accomplished prior to entering POWER OPERATION after every time the plant is placed in COLD SHUTDOWN for refueling, after each time the plant is placed in COLD SHUTDOWN for 72 hours if testing has not been accomplished in the preceding 9 months, and prior to returning the valve to service after maintenance, repair or replacement work is performed.	
20.	Containment Purge MOV Leakage	Functional	Semi-Annual (Unit at power or shutdown) if purge valves are operated during interval(c)	
21.	Deleted			
22.	RCS Flow	Flow ≥ 273,000 gpm and ≥ the limit as specified in the CORE OPERATING LIMITS REPORT	SFCP (d)	14
23.	Deleted			

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

(a) To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

(b) Minimum differential test pressure shall not be below 150 psid.

(c) Refer to Section 4.4 for acceptance criteria.

(d) Not required to be performed until 7 days after ≥ 90% RATED POWER.

* See Specification 4.1.D.

TABLE 4.1-2B
MINIMUM FREQUENCIES FOR SAMPLING TESTS

	DESCRIPTION	TEST	FREQUENCY	UFSAR SECTION REFERENCE
1.	Reactor Coolant Liquid Samples	Radio-Chemical Analysis (1)	SFCP (5)	
		Tritium Activity	SFCP (5)	9.1
		* Chemistry (CL, F & O2)	SFCP (9)	4
		* Boron Concentration	SFCP	9.1
		DOSE EQUIVALENT I-131	SFCP (4)(7)	
		DOSE EQUIVALENT XE-133	SFCP (4)	
2.	Refueling Water Storage	Chemistry (Cl & F)	SFCP	6
3.	Boric Acid Tanks	* Boron Concentration	SFCP	9.1
4.	NaTB Baskets	NaTB Buffer Analysis (2)	SFCP	6
5.	Spent Fuel Pit	* Boron Concentration	SFCP	9.5
6.	Secondary Coolant	DOSE EQUIVALENT I-131	SFCP	
7.	Stack Gas Iodine and Particulate Samples	* I-131 and particulate radioactive releases	SFCP	

* See Specification 4.1.D

SFCP - Surveillance frequencies are specified in the Surveillance Frequency Control Program.

(1) A radiochemical analysis will be made to evaluate the following corrosion products: Cr-51, Fe-59, Mn-54, Co-58, and Co-60.

(2) A laboratory test will be performed to verify that a sample from the NaTB baskets provides adequate pH adjustment of borated water.

(3) Deleted

(4) Whenever T_{avg} (average RCS temperature) exceeds 200°F.

(5) When reactor is critical and average primary coolant temperature $\geq$ 350°F.

(6) Deleted

(7) One sample between 2 and 6 hours following a THERMAL POWER change $\geq$ 15 percent of RATED POWER within a one hour period.

(8) Deleted.

(9) Sampling for chloride and fluoride concentrations is not required when fuel is removed from the reactor vessel and the reactor coolant inventory is drained below the reactor vessel flange, whether the upper internals and/or the vessel head are in place or not. Sampling for oxygen concentration is not required when the reactor coolant temperature is below 250 degrees F.

TABLE 4.1-3A

UNIT 1

MINIMUM FREQUENCY FOR FLUSHING SENSITIZED PIPE

	Flush Flow Path General Description	Flush Duration	Frequency
1)	Containment Spray Pump Discharge	Note 1	Note 2
2)	Low Hd SI Pump Discharge	Note 1	Note 2
3)	Low Hd SI Pump up to 1st Iso. Valve	Note 1	Note 2
4)	High Hd SI Pump Inside Containment	Note 1	Note 2
5)	High Hd SI Pump Discharge	Note 1	Note 2

Note 1: Flush until sample is below 0.15 PPM Cl^- and/or F^-

Note 2: When RWST Chemistry has exceeded 0.15 PPM Cl^- and/or F^- (only after restoring the RWST Chemistry to spec for Cl^- and/or F^-)

TABLE 4.1-3B

UNIT 2

MINIMUM FREQUENCY FOR FLUSHING SENSITIZED PIPE

Flush Flow Path General Description (Ref. S&W Report SW-MER-1A)	Flush Duration	Frequency
1) Containment Spray Pump Discharge	Note 1	Note 2
2) Low Hd SI Pump Discharge	Note 1	Note 2
3) Low Hd SI Pump up to 1st Iso. Valve	Note 1	Note 2
4) High Hd SI Pump Inside Containment	Note 1	Note 2
5) High Hd SI Pump Discharge	Note 1	Note 2

Note 1: Flush until sample is below 0.15 PPM Cl^- and/or F^-

Note 2: When RWST Chemistry has exceeded 0.15 PPM Cl^- and/or F^- (only after restoring the RWST Chemistry to spec for Cl^- and/or F^-)

4.2 REACTOR COOLANT PUMP FLYWHEEL INSPECTION

Applicability

Applies to an inservice inspection which augments that required by ASME Section XI.

Objective

To provide the additional assurance necessary for the continued integrity of an important component involved in safety and plant operation.

Specification

A. The Reactor Coolant Pump flywheel shall be inspected once every 20 years by a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius or a surface examination (MT and/or PT) of the exposed surfaces defined by the volume of the disassembled flywheels.

The provisions of Specification 4.0.2 are not applicable.

Basis

The inspection program for ASME Section XI of the ASME Boiler and Pressure Vessel Code limits its inspection to ASME Code Class 1, 2, and 3 components and supports. The Reactor Coolant Pump (RCP) flywheel inspection was added because there is no corresponding code requirement. The added requirement provides the inspection necessary to insure the continued integrity of the RCP flywheel.

The augmented inspection requirements for the low head safety injection piping in the valve pit, the low pressure turbine blades, and sensitized stainless steel have been relocated to the TRM.

Sensitized stainless steel augmented inspections were added to assure piping integrity of this classification.

Items 2.1.1-2.1.3

The examinations required by these items utilize the periodically updated ASME Section XI Boiler and Pressure Vessel Code for the augmented examinations. The surface and volumetric examinations required by items 2.1.1 and 2.1.2 will be conducted at three times the frequency required by the Code in an interval. In addition to the Code required pressure testing, visual examinations will be conducted, while the piping is pressurized by the procedures defined in Tables 4.1-3A & B of Technical Specification 4.1, concerning flushing of sensitized stainless steel piping. Weld selection criteria are modified from the Code for Class 1 welds, since stress level information as correlated to weld location is unavailable for Surry.

Item 2.2.1

The sensitized stainless steel located in the containment and recirculation spray rings in the overhead of containment are classified ASME Class 2 components. These components are currently exempted by ASME Section XI from surface and volumetric examination requirements. As such, an augmented program will remain in place requiring visual (VT-1) examination of these components for evidence of cracking. Additionally, sections of the piping will be examined by liquid penetrant inspection when the piping is visually inspected.

1.3	Primary Pump Flywheel	See remarks	See remarks	Inspect once every 20 years by a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle of one-half the outer radius or a surface examination (MT and/or PT) of exposed surfaces defined by the volume of the disassembled flywheels. The provisions of Specification 4.0.2 are not applicable.
1.4	Low Pressure Turbine Rotor	Visual and Magnetic Particle or Dye Penetrant	See remarks	100% of blades every six operating years. Inspections are normally performed concurrent with LP turbine rotor disk and hub inspections.

TABLE 4.2-1 (continued)

SECTION B. SENSITIZED STAINLESS STEEL

Item No.	Required Examination Area	Required Examination Methods	10-Year Interval Inspection	Remarks
2.1.1	Class 1 circumferential, longitudinal, branch pipe connection, and socket welds	As required by ASME Section XI	The welds examined by volumetric or surface techniques shall be conducted at three times the frequency required by ASME Section XI	A minimum of 5% of the welds shall be examined once per 18 months. At least 75% of the total population of welds shall be examined each interval. The same welds may be selected in subsequent intervals for examination. See Note 1.
2.1.2	Class 2 circumferential, longitudinal, branch pipe connection, and socket welds	As required by ASME Section XI	The welds examined by volumetric or surface techniques shall be conducted at three times the frequency required by ASME Section XI	A minimum of 2.5% of the welds shall be examined once per 18 months. At least 22.5% of the total population of welds shall be examined each interval. The same welds may be selected in subsequent intervals for examination. See Note 1.
2.1.3	Class 1 and Class 2 sensitized stainless steel pieces	Visual (VT-2) as required by ASME Section XI	As required by ASME Section XI	In addition to the Code required examinations the affected piping shall be visually (VT-2) examined during the flushing requirements of T.S. Tables 4.1-3A and 4.1-3B.

TABLE 4.2-1 (continued)

SECTION B. SENSITIZED STAINLESS STEEL

Item No.	Required Examination Area	Required Examination Methods	10-Year Interval Inspection	Remarks
2.2.1	Containment and Recirculation Spray Piping	Visual (VT-1) and surface examination	(See remarks)	At least 25% of the examinations shall have been completed by the expiration of one-third of the inspection interval and at least 50% shall have been completed by the expiration of two-thirds of the inspection interval. The remaining required examinations shall be completed by the end of the inspection interval. *Surface* examinations will include 6 patches (each 9 inches square) evenly distributed around each spray ring.

Note 1: a) The examinations shall be distributed among the systems prorated, to the degree practicable, on the number of sensitized stainless steel welds in each system (i.e., if a system contains 30% of the welds, then 30% of the required examinations shall be performed on that system).

b) Within a system terminal ends (e.g., branch connections, pipe to pump, pipe to valve) shall be selected. The remainder of the selection shall select structural discontinuities (pipe fittings) prorated to the degree practicable to the number of discontinuities in that system. Other selections may be necessary to meet the total weld selection criteria.

c) Within each system, examinations shall be distributed between line sizes prorated to the degree practicable.

4.3 DELETED

4.4 CONTAINMENT TESTS

Applicability

Applies to containment leakage testing.

Objective

To assure that leakage of the primary reactor containment and associated systems is held within allowable leakage rate limits; and to assure that periodic surveillance is performed to assure proper maintenance and leak repair during the service life of the containment.

Specification

A. Periodic and post-operational integrated leakage rate tests of the containment shall be performed in accordance with the requirements of 10 CFR 50, Appendix J, "Reactor Containment Leakage Testing for Water Cooled Power Reactors."

B. Containment Leakage Rate Testing Requirements

   1. The containment and containment penetrations leakage rate shall be demonstrated by performing leakage rate testing as required by 10 CFR 50 Appendix J, Option B, as modified by approved exemptions, and in accordance with the guidelines contained in NEI 94-01, Revision 3-A, "Industry Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J," dated July 2012.

   2. Leakage rate acceptance criteria are as follows:

      a. An overall integrated leakage rate of less than or equal to La, 0.1 percent by weight of containment air per 24 hours, at calculated peak pressure (Pa).

      b. A combined leakage rate of less than or equal to 0.60 La for all penetrations and valves subject to Type B and C testing when pressurized to Pa.

      Prior to entering an operating condition where containment integrity is required the as-left Type A leakage rate shall not exceed 0.75 La and the combined leakage rate of all penetrations subject to Type B and C testing shall not exceed 0.6 La.

   3. The provisions of Specification 4.0.2 are not applicable.

Basis

The leak tightness testing of all liner welds was performed during construction by welding a structural steel test channel over each weld seam and performing soap bubble and halogen leak tests.

The containment is designed for a maximum pressure of 45 psig. The containment is maintained at a subatmospheric air partial pressure consistent with TS Figure 3.8-1 depending upon the cooldown capability of the Engineered Safeguards and will not rise above 45 psig for any postulated loss-of-coolant accident.

The initial test pressure for the Type A test is 47.0 psig to allow for containment expansion and equalization. A review was performed to determine the effects of pressurizing containment above its design pressure of 45.0 psig. This review was based on the original containment test at 52 psig. During that test, the calculated stresses were found to be well within the allowable yield strength of the structural reinforcing bars, therefore performance of the Type A test at 47 psig will have no detrimental effect on the containment structure.

All loss-of-coolant accident evaluations have been based on an integrated containment leakage rate not to exceed 0.1% of containment volume per 24 hr.

The above specification satisfies the conditions of 10 CFR 50.54(o) which stated that primary reactor containments shall meet the containment leakage test requirements set forth in Appendix J.

The limitations on closure and leak rate for the containment airlocks are required to meet the restrictions on containment integrity and containment leak rate. Surveillance testing of the airlock seals provides assurance that the overall airlock leakage will not become excessive due to seal damage during the intervals between airlock leakage tests.

References

UFSAR Section 5.5	Containment Tests and Inspections
UFSAR Section 7.5.1	Design Bases of Engineered Safeguards Instrumentation
UFSAR Section 14.5	Loss of Coolant Accident
10 CFR 50 Appendix J	"Primary Reactor Containment Leakage Testing for Water Cooled Power Reactors"

4.5 SPRAY SYSTEMS TESTS

Applicability

Applies to the testing of the Spray Systems.

Objective

To verify that the Spray Systems will respond promptly and perform their design function, if required.

Specification

A. Each containment spray subsystem shall be demonstrated OPERABLE:

1. By verifying, that on recirculation flow, each containment spray pump performs satisfactorily when tested in accordance with the Inservice Testing Program.

2. By verifying that each motor-operated valve in the containment spray flow path performs satisfactorily when tested in accordance with the Inservice Testing Program.

3. By verifying each spray nozzle is unobstructed following maintenance which could cause nozzle blockage.

4. Coincident with the containment spray pump test described in Specification 4.5.A.1, by verifying that no particulate material clogs the test spray nozzles in the refueling water storage tank.

B. Each recirculation spray subsystem shall be demonstrated OPERABLE:

1. By verifying each recirculation spray pump performs satisfactorily when tested in accordance with the Inservice Testing Program.

2. By verifying that each motor-operated valve in the recirculation spray flow paths performs satisfactorily when tested in accordance with the Inservice Testing Program.

3. By verifying each spray nozzle is unobstructed following maintenance which could cause nozzle blockage.

C. In addition to the requirements of the Inservice Testing Program, each weight-loaded check valve in the containment spray and outside containment recirculation spray subsystems shall be demonstrated OPERABLE at the frequency specified in the Surveillance Frequency Control Program by cycling the valve one complete cycle of full travel and verifying that each valve opens when the discharge line of the pump is pressurized with air and seats when a vacuum is applied.

D. Verify, by visual inspection at the frequency specified in the Surveillance Frequency Control Program, that the recirculation spray containment sump components are not restricted by debris and show no evidence of structural distress or abnormal corrosion.

Basis

The flow testing of each containment spray pump is performed by opening the normally closed valve in the containment spray pump recirculation line returning water to the refueling water storage tank. The containment spray pump is operated and a quantity of water recirculated to the refueling water storage tank. The discharge to the tank is divided into two fractions; one for the major portion of the recirculation flow and the other to pass a small quantity of water through test nozzles which are identical with those used in the containment spray headers.

The purpose of the recirculation through the test nozzles is to assure that there are no particulate material in the refueling water storage tank small enough to pass through pump suction strainers and large enough to clog spray nozzles.

Due to the physical arrangement of the recirculation spray pumps inside the containment, it is impractical to flow-test them other than during a unit outage. Flow testing of these pumps requires the physical modification of the pump discharge piping and the erection of a temporary dike to contain recirculated water. The length of time required to setup for the test, perform the test, and then reconfigure the system for normal operation is prohibitive to performing the flow-test on even the cold shutdown frequency. Therefore, the flow-test of the inside containment recirculation spray pumps will be performed in accordance with the Inservice Testing Program during a unit outage.

The inside containment recirculation spray pumps are capable of being operated dry for approximately 60 seconds without significantly overheating and/or degrading the pump bearings. During this dry pump check, it can be determined that the pump shafts are turning by rotation sensors which indicate in the Main Control Room. In addition, motor current will be compared with an established reference value to ascertain that no degradation of pump operation has occurred.

The recirculation spray pumps outside the containment have the capability of being dry-run and flow tested. The test of an outside recirculation spray pump is performed by closing the containment sump suction line valve and the isolation valve between the pump discharge and the containment penetration. This allows the pump casing to be filled with water and the pump to recirculate water through a test line from the pump discharge to the pump casing.

With a system flush conducted to remove particulate matter prior to the installation of spray nozzles and with corrosion resistant nozzles and piping, it is not considered credible that a significant number of nozzles would plug during the life of the unit to reduce the effectiveness of the subsystems. Therefore, an inspection or air or smoke test of the nozzles following maintenance which could cause nozzle blockage is sufficient to indicate that plugging of the nozzles has not occurred.

The spray nozzles in the refueling water storage tank provide means to ensure that there is no particulate matter in the refueling water storage tank and the containment spray subsystems which could plug or cause deterioration of the spray nozzles. The nozzles in the tank are identical to those used on the containment spray headers. The flow test of the containment spray pumps and recirculation to the refueling water storage will indicate any plugging of the nozzles by a reduction of flow through the nozzles.

Periodic inspections of containment sump components ensure that the components are unrestricted and stay in proper operating condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

<u>References</u>

FSAR Section 6.3.1, Containment Spray Pumps

FSAR Section 6.3.1, Recirculation Spray Pumps

4.6 EMERGENCY POWER SYSTEM PERIODIC TESTING

Applicability

Applies to periodic testing and surveillance requirements of the Emergency Power System.

Objective

To verify that the Emergency Power System will respond promptly and properly when required.

Specification

The following tests and surveillance shall be performed as stated:

A. Diesel Generators

1. Tests and Frequencies

a. Manually initiated start of the diesel generator, followed by manual synchronization with other power sources and assumption of load by the diesel generator up to 2750 Kw. This test will be conducted at the frequency specified in the Surveillance Frequency Control Program on each diesel generator for a duration of 30 minutes. Normal station operation will not be affected by this test.

b. Automatic start of each diesel generator, load shedding, and restoration to operation of particular vital equipment, initiated by a simulated loss of off-site power together with a simulated safety injection signal. Testing will demonstrate load shedding and load sequencing initiated by a simulated loss of off-site power following a simulated engineered safety features signal. Testing will also demonstrate that the loss of voltage and degraded voltage protection is defeated whenever the emergency diesel is the sole source of power to an emergency bus and that this protection is automatically reinstated when the diesel output breaker is opened. This test will be conducted at the frequency specified in the Surveillance Frequency Control Program to assure that the diesel generator will start and accept load in less than or equal to 10 seconds after the engine starting signal.

c. Availability of the fuel oil transfer system shall be verified by operating the system in conjunction with TS 4.6.A.1.a surveillance.

d. Each diesel generator shall be given a thorough inspection at the frequency specified in the Surveillance Frequency Control Program utilizing the manufacturer's recommendations for this class of stand-by service.

2. Acceptance Criteria

The above tests will be considered satisfactory if all applicable equipment operates as designed.

B. Fuel Oil Storage Tanks for Diesel Generators

1. A minimum fuel oil storage of 35,000 gal shall be maintained on-site to assure full power operation of one diesel generator for seven days.

C. Station Batteries

1. Tests and Frequencies

The following Tests shall be performed at the frequencies specified in the Surveillance Frequency Control Program:

a. Measure the specific gravity, electrolytic temperature, cell voltage of the pilot cell in each battery, and the D.C. bus voltage of each battery.

b. Measure the voltage of each battery cell in each battery to the nearest 0.01 volts.

c. Measure the specific gravity of each battery cell, the temperature reading of every fifth cell, the height of electrolyte of each cell, and the amount of water added to any cell.

d. Compare the battery voltage and current after the battery charger has been turned off for approximately 5 min during normal operation.

e. Perform a simulated load test without battery charger on each station battery. The battery voltage and current as a function of time shall be monitored.

f. Check the battery connections for tightness and apply anti-corrosion coating to the interconnections.

2. Acceptance Criteria

a. Each test shall be considered satisfactory if the new data when compared to the old data indicate no signs of abuse or deterioration.

b. The load test in (d) and (e) above shall be considered satisfactory if the batteries perform within acceptable limits as established by the manufacturers discharge characteristic curves.

D. EMERGENCY DIESEL GENERATOR BATTERIES

1. TESTS AND FREQUENCIES

The following Tests shall be performed at the frequencies specified in the Surveillance Frequency Control Program:

a. Measure the specific gravity, electrolytic temperature, cell voltage of the pilot cell in each battery and the D.C. bus voltage of each battery.

b. Measure the voltage of each battery cell in each battery to the nearest 0.01 volts.

c. Measure the specific gravity of each battery cell, the temperature reading of every fifth cell, the height of electrolyte of each cell, and the amount of water added to any cell.

d. Perform a normal load or simulated load test without battery charger on each battery. The battery voltage and current as a function of time shall be monitored.

e. Check the battery connections for tightness and apply anti-corrosion coating to interconnections.

2. ACCEPTANCE CRITERIA

a. Each test shall be considered satisfactory if the new data when compared to the old data indicate no signs of abuse or deterioration.

b. The load test in (d) above shall be considered satisfactory if the batteries perform within acceptable limits as established by the manufacturers discharge characteristic curves.

Basis

The tests specified are designed to demonstrate that the diesel generators will provide power for operation of essential safeguards equipment. They also assure that the emergency diesel generator system controls and the control systems for the safeguards equipment will function automatically in the event of a loss of normal station service power.

The testing frequency specified in the Surveillance Frequency Control Program will be often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The fuel supply and starting circuits and controls are continuously monitored and any faults are alarm indicated. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

Station and emergency diesel generator batteries may deteriorate with time, but precipitous failure is extremely unlikely. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In addition alarms have been provided to indicate low battery voltage and low current from the inverters which would make it extremely unlikely that deterioration would go unnoticed.

The equalizing charge, as recommended by the manufacturer, is vital to maintaining the ampere-hour capability of the battery. As a check upon the effectiveness of the equalizing charge, the battery shall be loaded rather heavily and the voltage monitored as a function of time. If a cell has deteriorated or if a connection is loose, the voltage under load will drop excessively indicating the need for replacement or maintenance. FSAR Section 8.5 provides further amplification of the basis.

References

FSAR Section 8.5 Emergency Power System

4.7 MAIN STEAM LINE TRIP VALVES

Applicability

Applies to periodic testing of the main steam line trip valves.

Objective

To verify the ability of the main steam line trip valves to close upon signal.

Specification

A. Tests and Frequencies

1. Each main steam line trip valve shall be tested for full closure before each startup, unless a satisfactory test has been conducted within the previous 24 hours. The provisions of Specification 4.0.4 are not applicable.

B. Acceptance Criteria

1. A full closure test of a main steam line trip valve shall be considered satisfactory if the following criteria are met:

   a. T1 less than or equal to 4.0 seconds and
   b. T2 less than or equal to 5.0 seconds

   where

T1 = measured elapsed time from manual initiation of steam line isolation to initiation of main steam trip valve motion, seconds

T2 = measured elapsed main steam trip valve stroke time (full open to full closed), seconds

Basis

The main steam trip valves serve to limit an excessive Reactor Coolant System cooldown rate and resultant reactivity insertion following a main steam line break accident. Their ability to close fully within the maximum allowable time specified shall be verified prior to reactor startup.

The acceptance criteria reflect the assumptions made in the safety analysis of a main steam line break accident. The analysis assumes a 5 second delay from the time the system process variables reach the design setpoints to initiation of valve motion, followed by a 5 second linear ramp closure of the valve.

The acceptance criteria are established to ensure this safety analysis assumption is maintained. Thus the criteria may be written as follows:

a. I + B less than or equal to 5 seconds and
b. S less than or equal to 5 seconds

where

I = Instrument response time (delay from the time the process variable reaches the setpoint to initiation of bleedoff of instrument air from the main steam trip valve air cylinders), seconds.

B = Time delay from initiation of bleedoff of instrument air from the main steam trip valve air cylinders to initiation of valve motion, seconds.

S = Valve stroke time (full open to full closed), seconds.

The instrument response time I is represented by a value of 1.0 seconds based on a conservative evaluation of the actual response time. The bleedoff time B is equivalent to the measured interval T1 as defined in the Acceptance Criteria section of the Specification. The stroke time S is conservatively approximated by the measured interval T2 as defined in the Specification. Under actual steam line break conditions it is expected that S will be much less than T2, since valve closure is flow assisted. Thus the acceptance criterion may be rewritten as shown in Section 4.7.B.1.

4.8 AUXILIARY FEEDWATER SYSTEM

Applicability

Applies to the periodic testing requirements of the Auxiliary Feedwater System.

Objective

To verify the operability of the auxiliary feedwater pumps.

Specification

A. Tests and Frequencies

The following Tests shall be performed at the frequencies specified in the Surveillance Frequency Control Program unless otherwise noted below:

1. Verify that the Auxiliary Feedwater System manual, power operated, and automatic valves in each flowpath are in the correct position. This verification includes valves that are not locked, sealed, or otherwise secured in position, valves in the cross-connect from the opposite unit and valves in the steam supply paths to the turbine driven auxiliary feedwater pump.

2. Verify that each motor-operated valve in the auxiliary feedwater flowpaths, including the cross-connect from the opposite unit, performs satisfactorily when tested in accordance with the Inservice Testing Program.

3. Verify that the auxiliary feedwater pumps perform satisfactorily when tested in accordance with the Inservice Testing Program. The provisions of Specification 4.0.4 are not applicable for the turbine driven pump. Note that the developed head test of the turbine driven pump is required to be performed within 24 hours after reaching HOT SHUTDOWN.

4. Whenever the unit's Reactor Coolant System temperature and pressure have been less than 350°F and 450 psig, respectively, for a period greater than 30 days, prior to Reactor Coolant System temperature and pressure exceeding 350°F and 450 psig, respectively, verify proper alignment of the required auxiliary feedwater flowpaths by verifying flow from the 110,000 gallon above ground Emergency Condensate Storage Tank to the steam generators from each of the auxiliary feedwater pumps.

5. During periods of reactor shutdown with the opposite unit's Reactor Coolant System temperature and pressure greater than 350°F and 450 psig, respectively:

   a. Continue to verify that the motor driven auxiliary feedwater pumps perform satisfactorily when tested at the frequency defined in Specification 4.8.A.3.

   b. Verify that each motor-operated valve in the auxiliary feedwater cross-connect flowpath for the opposite unit performs satisfactorily when tested in accordance with the Inservice Testing Program.

6. Verify automatic actuation of:

   a. Each auxiliary feedwater automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.

   b. Each auxiliary feedwater pump starts automatically on an actual or simulated actuation signal. Note that this surveillance is required to be performed for the turbine driven pump within 24 hours after reaching HOT SHUTDOWN.

B. Acceptance Criteria

The pump and valve tests shall be considered satisfactory if they meet the Inservice Testing Program acceptance criteria.

The flowpath alignment tests during unit startup from REFUELING, COLD, or INTERMEDIATE SHUTDOWN shall be considered satisfactory if the control board indication demonstrates that flowpaths exist to each steam generator.

Basis

The correct alignment for manual, power operated, and automatic valves in the Auxiliary Feedwater System steam and water flowpaths, including the cross-connect flowpath, will provide assurance that the proper flowpaths exist for system operation. This position check does not include: 1) valves that are locked, sealed or otherwise secured in position since they are verified to be in their correct position prior to locking, sealing or otherwise securing; 2) vent, drain or relief valves on those flowpaths; and, 3) those valves that cannot be inadvertently misaligned such as check valves. This surveillance does not require any testing or valve manipulation. It involves verification that those valves capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Valves in the auxiliary feedwater flowpaths to the steam generators and cross-connect flow path are tested periodically in accordance with the Inservice Testing Program. The auxiliary feedwater pumps are tested periodically in accordance with the Inservice Testing Program to demonstrate operability. Verification of the developed head of each auxiliary feedwater pump ensures that the pump performance has not degraded. Flow and differential head tests are normal inservice testing requirements. Because it is sometimes undesirable to introduce cold auxiliary feedwater into the steam generators while they are operating, the inservice testing is typically performed on recirculation flow to the 110,000 gallon Emergency Condensate Storage Tank.

Appropriate surveillance and post-maintenance testing is required to declare equipment OPERABLE. Testing may not be possible in the applicable plant conditions due to the necessary unit parameters not having been established. In this situation, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible, and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a condition where other necessary surveillance or post maintenance tests can be completed. Relative to the turbine driven auxiliary feedwater pump, Specification 4.8.A.3 is modified by a note indicating that the developed head test of the turbine driven pump should be deferred until suitable conditions are established; this deferral is required because there may be insufficient steam pressure to perform the test.

The auxiliary feedwater pumps are capable of supplying feedwater to the opposite unit's steam generators. For a main steam line break or fire event in the Main Steam Valve House, one of the opposite units auxiliary feedwater pumps is required to supply feedwater to mitigate the consequences of those accidents. Therefore, when considering a single failure, both motor driven auxiliary feedwater pumps are required to be OPERABLE* during shutdown to support the opposite unit if the Reactor Coolant System temperature or pressure of the opposite unit is greater than 350°F and 450 psig, respectively. Thus, to establish operability* the motor driven auxiliary feedwater pumps will continue to be tested in accordance with the Inservice Testing Program when the unit is shutdown to support the opposite unit.

The capacity of the Emergency Condensate Storage Tank and the flow rate of any one of the three auxiliary feedwater pumps in conjunction with the water inventory of the steam generators is capable of maintaining the plant in a safe condition and sufficient to cool the unit down.

Proper functioning of the steam turbine admission valve and the ability of the auxiliary feedwater pumps to start will demonstrate the integrity of the system. Verification of correct operation can be made both from instrumentation within the Main Control Room and direct visual observation of the pumps.

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* excluding automatic initiation instrumentation

References

UFSAR Section 10.3.1, Main Steam System

UFSAR Section 10.3.2, Auxiliary Steam System

UFSAR Section 10.3.5, Condensate and Feedwater Systems

4.9 RADIOACTIVE GAS STORAGE MONITORING SYSTEM

Applicability

Applies to the periodic monitoring of radioactive gas storage.

Objective

To ascertain that waste gas is stored in accordance with Specification 3.11.

Specification

A. The concentration of oxygen in the waste gas holdup system shall be determined to be within the limits of Specification 3.11.A by continuously monitoring the waste gases in the waste gas holdup system with the oxygen monitor required to be OPERABLE by Table 3.7-5(a) of Specification 3.7.D.

B. The quantity of radioactive material contained in each gas storage tank shall be determined to be within the limits of Specification 3.11.B at the frequency specified in the Surveillance Frequency Control Program when the specific activity of the primary reactor coolant is ≤ 2200 μCi/gm dose equivalent Xe-133. Under the conditions which result in a specific activity > 2200 μCi/gm dose equivalent Xe-133, the waste gas decay tanks shall be sampled once per day.

4.10 REACTIVITY ANOMALIES

Applicability

Applies to potential reactivity anomalies.

Objective

To require evaluation of applicable reactivity anomalies within the reactor.

Specification

A. Following a normalization of the computed boron concentration as a function of burnup, the actual boron concentration of the coolant shall be compared with the predicted value at the frequency specified in the Surveillance Frequency Control Program. If the difference between the observed and predicted steady-state concentrations reaches the equivalent of one percent in reactivity, an evaluation as to the cause of the discrepancy shall be made. The provisions of Specification 4.0.4 are not applicable.

B. During periods of POWER OPERATION at greater than 10% of RATED POWER, the hot channel factors identified in Section 3.12 shall be determined during each effective full power month of operation using data from limited core maps. If these factors exceed their limits, an evaluation as to the cause of the anomaly shall be made. The provisions of Specification 4.0.4 are not applicable.

DELETED

Basis

BORON CONCENTRATION

To eliminate possible errors in the calculations of the initial reactivity of the core and the reactivity depletion rate, the predicted relation between fuel burnup and the boron concentration necessary to maintain adequate control characteristics must be adjusted (normalized) to accurately reflect actual core conditions. When full power is reached initially, and with the control rod assembly groups in the desired positions, the boron concentration is measured and the predicted curve is adjusted to this point. As power operation proceeds, the measured boron concentration is compared with the predicted concentration, and the slope of the curve relating burnup and reactivity is compared with that predicted. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This process of normalization should be completed after about 10% of the total core burnup. Thereafter, actual boron concentration can be compared with prediction, and the reactivity status of the core can be continuously evaluated. Any reactivity anomaly greater than 1% would be unexpected, and its occurrence would be thoroughly investigated and evaluated.

The value of 1% is considered a safe limit since a shutdown margin of at least 1% with the most reactive control rod assembly in the fully withdrawn position is always maintained.

PEAKING FACTORS

A thermal criterion in the reactor core design specified that "no fuel melting during any anticipated normal operating condition" should occur. To meet the above criterion during a thermal overpower of 118% with additional margin for design uncertainties, a steady state maximum linear power is selected. This then is an upper linear power limit determined by the maximum central temperature of the hot pellet.

The peaking factor is a ratio taken between the maximum allowed linear power density in the reactor to the average value over the whole reactor. It is of course the average value that determines the operating power level. The peaking factor is a constraint which must be met to assure that the peak linear power density does not exceed the maximum allowed value.

During normal reactor operation, measured peaking factors should be significantly lower than design limits. As core burnup progresses, measured designed peaking factors typically decrease. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

4.11 SAFETY INJECTION SYSTEM TESTS

Applicability

Applies to the operational testing of the Safety Injection System.

Objective

To verify that the Safety Injection System will respond promptly and perform its design functions, if required.

Specifications

A. The refueling water storage tank (RWST) shall be demonstrated OPERABLE at the frequency specified in the Surveillance Frequency Control Program by:

1. Verifying the RWST solution temperature is within specified limits.
2. Verifying:
    a. The RWST contained borated water volume, and
    b. The RWST boron concentration are within specified limits.

B. Each safety injection accumulator shall be demonstrated OPERABLE at the frequency specified in the Surveillance Frequency Control Program or as specified below by:

1. Verifying:
    a. The contained borated water volume, and
    b. The nitrogen cover-pressure are within specified limits.

2. Verifying:

   a. The boron concentration of the accumulator solution is within specified limits, and

   b. The boron concentration of the accumulator solution within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume.

   Note: Surveillance 4.11.B.2.b is not required when the volume increase makeup source is the RWST.

C. Each Safety Injection Subsystem shall be demonstrated OPERABLE at the frequency specified in the Surveillance Frequency Control Program unless otherwise noted below by:

1. Verifying, that on recirculation flow, each low head safety injection pump performs satisfactorily when tested in accordance with the Inservice Testing Program.

2. Verifying that each charging pump performs satisfactorily when tested in accordance with the Inservice Testing Program.

3. Verifying that each motor-operated valve in the safety injection flow path performs satisfactorily when tested in accordance with the Inservice Testing Program.

4. Prior to POWER OPERATION by:

   a. Verifying that the following motor operated valves are blocked open by de-energizing AC power to the valves motor operator and tagging the breaker in the off position:

Unit 1	Unit 2
MOV-1890C	MOV-2890C

   b. Verifying that the following motor operated valves are blocked closed by de-energizing AC power to the valves motor operator and the breaker is locked, sealed or otherwise secured in the off position:

Unit 1	Unit 2
MOV-1869A	MOV-2869A
MOV-1869B	MOV-2869B
MOV-1890A	MOV-2890A
MOV-1890B	MOV-2890B

c. Power may be restored to any valve or breaker referenced in Specifications 4.11.C.4.a and 4.11.C.4.b for the purpose of testing or maintenance provided that not more than one valve has power restored at one time, and the testing and maintenance is completed and power removed within 24 hours.

5. Verifying:

a. That each automatic valve capable of receiving a safety injection signal, actuates to its correct position upon receipt of a safety injection test signal. The charging and low head safety injection pumps may be immobilized for this test.

b. That each charging pump and safety injection pump circuit breaker actuates to its correct position upon receipt of a safety injection test signal. The charging and low head safety injection pumps may be immobilized for this test.

c. By visual inspection that the low head safety injection containment sump components are not restricted by debris and show no evidence of structural distress or abnormal corrosion.

d. That the Safety Injection System locations susceptible to gas accumulation are sufficiently filled with water.

Basis

Complete system tests cannot be performed when the reactor is operating because a safety injection signal causes containment isolation. The method of assuring operability of these systems is therefore to combine system tests to be performed during unit outages, with more frequent component tests, which can be performed during reactor operation.

The system tests demonstrate proper automatic operation of the Safety Injection (SI) System. A test signal is applied to initiate automatic operation action and verification is made that the components receive the safety injection signal in the proper sequence. The test may be performed with the pumps blocked from starting. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.

During reactor operation, the instrumentation which is depended on to initiate safety injection is checked periodically, and the initiating circuits are tested in accordance with Specification 4.1. In addition, the active components (pumps and valves) are to be periodically tested to check the operation of the starting circuits and to verify that the pumps are in satisfactory running order. The test interval is determined in accordance with the Inservice Testing Program. The accumulators are a passive safeguard.

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation are necessary for proper operation of the ECCS and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of SI System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review was supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configurations, such as stand-by versus operating conditions.

The SI System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criterion for gas volume at the suction or discharge of a pump), the surveillance is not met. If it is determined by subsequent evaluation that the SI System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

SI System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations, alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system operability. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system operability during the surveillance interval.

System vent flow paths opened under administrative control are permitted to perform the surveillance. The administrative control will be appropriately documented (e.g., proceduralized) and will include stationing a dedicated individual at the system vent flow path who is in continuous communication with the operators in the control room. This individual will have a method to rapidly close the system vent flow path if directed.

The monitoring frequency takes into consideration the gradual nature of gas accumulation in the SI Subsystem piping and the procedural controls governing system operation and is controlled by the Surveillance Frequency Control Program. The surveillance frequency may vary by each location's susceptibility to gas accumulation.

Periodic inspections of containment sump components ensure that the components are unrestricted and stay in proper operating condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

References

UFSAR Section 6.2, Safety Injection System

4.12 AUXILIARY VENTILATION EXHAUST FILTER TRAINS

Applicability

Applies to the testing of safety-related air filtration systems.

Objective

To verify that leakage efficiency and iodine removal efficiency are within acceptable limits.

Specifications

A. Tests and Frequency

The following Tests shall be performed at the frequencies specified in the Surveillance Frequency Control Program or as specified below and as required for the conditions identified below:

1. Operate each redundant filter train circuit.

2. Demonstrate the operability of the entire safety-related portion of the auxiliary ventilation system.

3. Determine auxiliary ventilation system exhaust fan flow rate through each filter train in the LOCA mode of operation initially, after any structural maintenance on the HEPA filter or charcoal adsorber housings, once per 18 months, or after partial or complete replacement of the HEPA filters of charcoal adsorbers.

   The procedure for determining the air flow rate shall be in accordance with Section 9 of the ACGIH Industrial Ventilation document and Section 8 of ANSI N510-1975.

4. Conduct a visual inspection of the filter train and associated components before each in-place air flow distribution test, DOP test, or activated charcoal adsorber leak test in accordance with the intent of Section 5 of ANSI N510-1975.

5. Perform an air distribution test across the prefilter bank initially and after any major modification, major repair, or maintenance of the air cleaning system affecting the filter bank flow distribution. The air distribution test shall be performed with an anemometer located at the downstream side and at the center of each carbon filter.

6. Perform in-place cold DOP tests for HEPA filter banks:

   a. Initially;

   b. Once per 18 months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of the HEPA filter cells; and

   e. After any structural maintenance on the filter housing.

   The procedure for in-place cold DOP tests shall be in accordance with ANSI N510-1975, Section 10.5 or 11.4. The flow rate during the in-place cold DOP tests shall be 36,000 CFM ±10 percent. The flow rate shall be determined by recording the flow meter reading in the control room.

7. Perform in-place halogenated hydrocarbon leakage tests for the charcoal adsorber bank:

   a. Initially;

   b. Once per 18 months;

c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

d. After each complete or partial replacement of charcoal adsorber trays; and

e. After any structural maintenance of the filter housing.

The procedure for in-place halogenated hydrocarbon leakage tests shall be in accordance with ANSI N510-1975, Section 12.5. The flow rate during the in-place halogenated hydrocarbon leakage tests shall be 36,000 CFM ±10 percent. The flow rate shall be determined by recording the flow meter reading in the control room.

8. Perform laboratory analysis of each charcoal train:

a. Initially, whenever a new batch of charcoal is used to fill adsorbers trays; and

b. After 720 hours of train operation; and

c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation; and

d. After any structural maintenance on the HEPA filter or charcoal adsorber housings that could affect operation of the charcoal adsorber; and

e. At least once per eighteen months, if not otherwise performed per condition 8.b, 8.c, or 8.d within the last eighteen months.

The procedure for iodine removal efficiency tests shall follow ASTM D3803. The test conditions shall be in accordance with those listed in Specification 4.12.B.7.

9. Check the pressure drop across the HEPA filter and adsorber banks:

    a. Initially;

    b. Once per 18 months thereafter for systems maintained in a standby status and after 720 hours of system operation; and

    c. After each complete or partial replacement of filters or adsorbers.

B. Acceptance Criteria

1. The minimum period of air flow through the filters shall be 15 minutes.

2. The system operability test of Specification 4.12.A.2 shall demonstrate automatic start-up, shutdown and flow path alignment.

3. The air flow rate determined in Specification 4.12.A.3 shall be:

    a. 36,000 cfm ±10 percent with system in the LOCA mode of operation.

    b. The ventilation system shall be adjusted until the above limit is met.

4. Air distribution test across the prefilter-bank shall show uniformity of air velocity within ± 20 percent of average velocity. The ventilation system shall be adjusted until the limit is met.

5. In-place cold DOP test on HEPA filters shall show greater than or equal to 99.5 percent DOP removal. Leakage sources shall be identified, repaired, and retested. Any HEPA filters found defective shall be replaced.

6. In-place halogenated hydrocarbon leakage tests on charcoal adsorber banks shall show greater than or equal to 99 percent halogenated hydrocarbon removal. Leakage sources shall be identified, repaired, and retested.

7. Laboratory analysis on charcoal samples of the in-place charcoal adsorber, or new adsorbent, when obtained as described in Regulatory Guide 1.52, Revision 2, shall show:

   Methyl iodide penetration less than or equal to 14 percent, when tested in accordance with ASTM D3803-1989 (with the exception of face velocity which is to be at 24.4 M/min), with the relative humidity equal to 95 percent, and the temperature equal to 30°C (86°F).

   a. Laboratory analysis of charcoal adsorbers shall be available within 31 days of sampling.

   b. If the test results are unacceptable for the in-place charcoal adsorber, all the adsorbent in the affected filter shall be replaced with new qualified adsorbent.

8. The pressure drop across filter cells and adsorbers shall not exceed 7.0 inches W.G. If this condition cannot be met, new filter cells shall be installed.

Basis

Ventilation system filter components are not subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. The tests outlined above provide assurance of filter reliability and will ensure timely detection of conditions which could cause filter degradation.

A pressure drop across the combined HEPA filters and charcoal adsorbers of less than 7 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Operation of the filtration system for a minimum of 15 minutes at the frequency specified in the Surveillance Frequency Control Program prevents moisture buildup in the filters and adsorbers. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The frequency of tests and sample analysis of the degradable components of the system, i.e., the HEPA filter and charcoal adsorbers, is based on actual hours of operation to ensure that they perform as evaluated. System flow rates and air distribution do not change unless the ventilation system is radically altered.

If painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from the fumes, chemical, or foreign material, the same tests and sample analysis are performed as required for operational use.

The in-place test results should indicate a system leak tightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99.5 percent removal of DOP particulates. The heat release from operating ECCS equipment limits the relative humidity of the exhaust air to less than 80 percent even when outdoor air is assumed to be 100 percent relative humidity and all ECCS leakage evaporates into the exhaust air stream. Methyl iodide testing to a penetration less than or equal to 14 percent (applying a safety factor of 2) demonstrates the assumed accident analysis efficiencies of 70 percent for methyl iodide and 90 percent for elemental iodine. This conclusion is supported by a July 10, 2000 letter from NCS Corporation that stated "Nuclear grade activated carbon, when tested in accordance with ASTM D3803-1989 (methyl iodide...) to a penetration of 15%, is more conservative than testing the same carbon in accordance with ASTM D3803-1979 (elemental iodine...) to a penetration of 5%. ...As a general rule, you may expect the radioiodine penetration through nuclear grade activated carbon to increase from 20 to 100 times when switching from elemental iodine to methyl iodide testing." Therefore, the efficiencies of the HEPA filters and charcoal adsorbers are demonstrated to be as specified, at flow rates, temperatures, velocities, and relative humidities which are less than the design values of the system, the resulting doses will be less than or equal to the limits specified in 10 CFR 50.67 or Regulatory Guide 1.183 for the accidents analyzed. The demonstration of bypass 1% and demonstration of 86 percent methyl iodide removal efficiency will assure the required capability of the adsorbers is met or exceeded.

4.13 RCS OPERATIONAL LEAKAGE

Applicability

The following specifications are applicable to RCS operational LEAKAGE whenever T_{avg} (average RCS temperature) exceeds 200°F (200 degrees Fahrenheit).

Objective

To verify that RCS operational LEAKAGE is maintained within the allowable limits, the following surveillances shall be performed at the frequencies specified in the Surveillance Frequency Control Program.

Specifications

A. Verify RCS operational LEAKAGE is within the limits specified in TS 3.1.C by performance of RCS water inventory balance.[1, 2]

B. Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.[1]

Notes:

1. Not required to be completed until 12 hours after establishment of steady state operation.
2. Not applicable to primary to secondary LEAKAGE.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.13.A

Verifying RCS LEAKAGE to be within the Limiting Condition for Operation (LCO) limits ensures the integrity of the reactor coolant pressure boundary (RCPB) is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions (stable pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The surveillance is modified by two notes. Note 1 states that this SR is not required to be completed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable unit conditions are established.

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in the TS 3.1.C Bases.

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 4.13.B

This SR verifies that primary to secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.1.H, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG.

If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG. The surveillance is modified by a Note, which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 4.13.A and SR 4.13.B / Note 1

With respect to SR 4.13.A and SR 4.13.B, as the associated Note 1 modifies the required completion of the surveillance, it is construed to be part of the specified completion time. Should the surveillance interval be exceeded while steady state operation has not been established, Note 1 allows 12 hours after establishment of steady state operation to complete the surveillance. The surveillance is still considered to be completed within the specified completion time. Therefore, if the surveillance were not completed within the required surveillance interval (plus extension allowed by TS 4.0.2) interval, but steady state operation had not been established, it would not constitute a failure of the SR. Once steady state operation is established, 12 hours would be allowed for completing the surveillance. If the surveillance were not completed within this 12 hour interval, there would a failure to complete a surveillance within the specified completion time, and the provisions of SR 4.0.3 would apply.

REFERENCES

1. UFSAR, Chapter 4, Surry Units 1 and 2.
2. UFSAR, Chapter 14, Surry Units 1 and 2.
3. NEI 97-06, "Steam Generator Program Guidelines."
4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

4.15 AUGMENTED INSERVICE INSPECTION PROGRAM FOR HIGH ENERGY LINES OUTSIDE OF CONTAINMENT (RELOCATED TO TRM)

Pages TS 4.15-2 through TS 4.15-4 and TS Figure 4.15 have been deleted.

4.16 LEAKAGE TESTING OF MISCELLANEOUS RADIOACTIVE MATERIALS SOURCES

Applicability

Applies to miscellaneous radioactive materials sealed sources not subject to core flux and that are not stored and out of use.

Objective

To maintain doses due to ingestion or inhalation within the limits of 10 CFR 20.

Specifications

A. Source Leakage Test

Radioactive sources shall be leak tested for contamination. The leakage test shall be capable of detecting the presence of 0.005 microcurie of radioactive material on the test sample. If the test reveals the presence of 0.005 microcurie or more of removable contamination, it shall immediately be withdrawn from use, decontaminated, and repaired or be disposed of in accordance with Commission regulations.

Those quantities of byproduct material that exceed that quantities listed in 10 CFR 30.71 Schedule B are to be leak tested in accordance with the schedule shown in Surveillance Requirements. All other sources (including alpha emitters) containing greater than 0.1 microcurie are also to be leak tested in accordance with the Surveillance Requirements.

B. Surveillance Requirements

1. Test for leakage and/or contamination shall be performed by the licensee or by other persons specifically authorized by the

   Commission or an agreement State as follows:

   a. Each sealed source, except startup sources subject to core flux, containing radioactive material other than Hydrogen 3 with a half-life greater than thirty days and in any form other than gas shall be tested for leakage and/or contamination at the frequency specified in the Surveillance Frequency Control Program.

   b. The periodic leak test required does not apply to sealed sources that are stored and not being used. The sources excepted from this test shall be tested for leakage prior to any use or transfer to another user unless they have been leak tested at the frequency specified in the Surveillance Frequency Control Program prior to the date of use or transfer. In the absence of a certificate from a transferor indicating that a test has been made within the frequency specified in the Surveillance Frequency Control Program prior to the transfer, sealed sources shall not be put into use until tested.

   c. Startup sources shall be leak tested prior to and following any repair or maintenance and before being subjected to core flux.

2. A complete inventory of radioactive materials in possession shall be maintained current at all times.

Basis

Ingestion or inhalation of source material may give rise to total body or organ irradiation. This specification assures that leakage from radioactive materials sources does not exceed allowable limits. The limits for all other sources (including alpha emitters) are based upon 10 CFR 70.39(c) limits for plutonium.

4.17 SHOCK SUPPRESSORS (SNUBBERS)

Applicability

Applies to all hydraulic and mechanical shock suppressors (snubbers) which are required to protect the Reactor Coolant System and other safety-related systems. Snubbers excluded from this inspection are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system.

Objective

To specify the minimum frequency and type of surveillance to be applied to the hydraulic and mechanical snubbers required to protect the Reactor Coolant System and other safety-related systems.

Specification

Each snubber shall be demonstrated OPERABLE by performance of the Units 1 and 2 Inservice Examination, Testing, and Service Life Monitoring Program Plans for Snubbers. The Program is defined in TS 6.4.T.

A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the action requirements of Specification 3.20 shall be met.

Bases

All snubbers are required operable to ensure that the structural integrity of the reactor coolant system and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on non-safety-related systems and then only if their failure or failure of the system on which they are installed would have no adverse effect on any safety-related system.

Pages 4.17-3 through 4.17-52 have been deleted.

4.18 MAIN CONTROL ROOM/EMERGENCY SWITCHGEAR ROOM (MCR/ESGR) EMERGENCY VENTILATION SYSTEM (EVS) TESTING

A. Operate each MCR/ESGR EVS train for ≥ 15 minutes in accordance with the frequency specified in the Surveillance Frequency Control Program.

B. Perform required Control Room Air Filtration System Testing in accordance with TS 4.20.

C. Perform required MCR/ESGR envelope unfiltered air inleakage testing in accordance with the MCR/ESGR Envelope Habitability Program.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.18.A

Standby systems should be checked periodically to ensure that they function properly. Systems without heaters need only be operated for ≥ 15 minutes to demonstrate the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Operation of the MCR/ESGR EVS trains shall be initiated manually from the MCR.

SR 4.18.B

This SR verifies that the required Control Room Air Filtration System testing is performed in accordance with Specification 4.20. Specification 4.20 includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in TS 4.20.

SR 4.18.C

This SR verifies the OPERABILITY of the MCR/ESGR envelope boundary by testing for unfiltered air inleakage past the MCR/ESGR envelope boundary and into the MCR/ESGR envelope. The details of the testing are specified in the MCR/ESGR Envelope Habitability Program (TS 6.4.R).

The MCR/ESGR envelope is considered habitable when the radiological dose to MCR/ESGR envelope occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE, and the MCR/ESGR envelope occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the MCR/ESGR envelope is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Specification 3.21.C must be entered. Specification 3.21.C.3 allows time to restore the MCR/ESGR envelope boundary to OPERABLE status provided mitigating actions can ensure that the MCR/ESGR envelope remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 1) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 2). These compensatory measures may also be used as mitigating actions as required by Specification 3.21.C.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 3). Options for restoring the MCR/ESGR envelope boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the MCR/ESGR envelope boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the MCR/ESGR envelope boundary has been restored to OPERABLE status.

REFERENCES

1. Regulatory Guide 1.196, "Control Room Habitability at Light-Water Nuclear Power Reactors"

2. NEI 99-03, "Control Room Habitability Assessment," June 2001

3. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability" (ADAMS Accession No. ML040300694)

4.19 STEAM GENERATOR (SG) TUBE INTEGRITY

Applicability

Applies to the verification of SG tube integrity in accordance with the Steam Generator Program.

Objective

To provide assurance of SG tube integrity.

Specifications

A. Verify SG tube integrity in accordance with the Steam Generator Program.

B. Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program prior to T_{avg} exceeding 200°F following a SG tube inspection.

BASES

SURVEILLANCE REQUIREMENTS (SR)

SR 4.19.A

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the frequency of SR 4.19.A. The frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 7). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.4.Q contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 6.4.Q until subsequent inspections support extending the inspection interval.

SR 4.19.B

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 6.4.Q are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 and Reference 7 provide guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The frequency of prior to T_{avg} exceeding 200°F following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

<u>REFERENCES</u>

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 50.67.
4. Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000.
5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
6. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
7. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

4.20 CONTROL ROOM AIR FILTRATION SYSTEM

Applicability

Applies to the testing of safety-related air filtration systems of the control room and relay room.

Objective

To verify that leakage efficiency and iodine removal efficiency are within acceptable limits.

Specification

A. Tests and Frequency

1. The control room air filtration system flow rate test shall be performed:

   a. Initially;

   b. Once per 18 months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of the HEPA filter or charcoal adsorbers; and

   e. After any structural maintenance the HEPA filter or charcoal adsorber housings; and

   f. After any major modification or repair of the air cleaning system.

2. The procedure for determining the air flow rate shall be in accordance with Section 9 of the ACGIH Industrial Ventilation document and Section 8 of ANSI N510-1975. A visual inspection of the filter train and its associated components shall be conducted before each in-place airflow distribution test, DOP test, or activated charcoal adsorber leak test in accordance with the intent of Section 5 of ANSI N510-1975.

3. In-place cold DOP tests for HEPA filter banks shall be performed:

   a. Initially;

   b. Once per 18 months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of the HEPA filter cells; and

   e. After any structural maintenance of the filter housing.

4. The procedure for in-place cold DOP tests shall be in accordance with ANSI N510-1975, Section 10.5 or 11.4. The flow rate during this test shall be that value determined under Specification 4. 20. A. 1 and shall be within the range specified in Specification 4. 20. B. 1.

5. In-place halogenated hydrocarbon leakage tests for the charcoal adsorber bank shall be performed:

   a. Initially;

   b. Once per eighteen months;

   c. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation;

   d. After each complete or partial replacement of charcoal adsorber trays; and

   e. After any structural maintenance on the filter housing.

6. The procedure for in-place halogenated hydrocarbon leakage tests shall be in accordance with ANSI N510-1975 Section 12.5. The flow rate during this test shall be that value determined under Specification 4.20.A.1 and shall be within the range specified in Specification 4.20.B.1.

7. Charcoal Adsorber shall be replaced:

   a. After 720 hours of train operation; and

   b. Following painting, fire, or chemical release in any ventilation zone communicating with the system during system operation; and

   c. After any structural maintenance on the HEPA filter or charcoal adsorber housing that could affect the operation of the charcoal adsorber; and

   d. At least once per eighteen months, if not otherwise replaced per condition 7.a, 7.b, or 7.c within the last eighteen months.

Upon meeting any of these conditions, the affected charcoal bank shall be removed from service and the charcoal replaced with new charcoal meeting the specifications in 4.20.B.4.

8. The procedure for iodine removal efficiency tests shall follow ASTM D3803. The test conditions shall be in accordance with those listed in Specification 4.20.B.4.

9. The pressure drop across the HEPA filter and adsorber banks shall be checked:

   a. Initially;

   b. Once per 18 months; and

   c. After each complete or partial replacement of filters or adsorbers.

B. Acceptance Criteria

1. Fan flow tube test shall show a flow rate through any single filter train of 1000 ± 10 percent cfm.

2. In-place cold DOP tests on HEPA filters shall show greater than or equal to 99.5 percent DOP removal. Leaking sources shall be identified, repaired and retested. Any HEPA filter found defective shall be replaced.

3. In-place halogenated hydrocarbon leakage tests on charcoal adsorber banks shall show greater than or equal to 99 percent halogenated hydrocarbon removal. Leakage sources shall be identified, repaired and retested.

4. Laboratory analysis on new charcoal adsorbent shall show the methyl iodide penetration less than or equal to 14 percent, when tested in accordance with ASTM D3803-1989 (with the exception of face velocity which is to be at 24.4 M/min), with the relative humidity equal to 95 percent, and the temperature equal to 30°C (86°F).

5. The pressure drop across filter cells and adsorbers shall not exceed 5.0 inches W.G. at design flow rate. If this condition cannot be met, new filter cells shall be installed.

Basis

Ventilation system filter components are not subject to rapid deterioration, having lifetimes of many years. The tests outlined above provide assurance of filter reliability and will ensure timely detection of conditions which could cause filter degradation.

A pressure drop across the combined HEPA filters and charcoal adsorbers of less than 5 inches of water will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter.

The frequency of tests and sample analysis are necessary to show that the HEPA filters and charcoal adsorbers can perform as evaluated.

If painting, fire, or chemical release occurs such that the HEPA filter or charcoal adsorber could become contaminated from fumes, chemicals, or foreign material, the HEPA filters are tested and the charcoal adsorbers are replaced to ensure the operational requirements are met.

The in-place test results should indicate a system leaktightness of less than 1 percent bypass leakage for the charcoal adsorbers and a HEPA efficiency of at least 99.5 percent removal of DOP particulates. Methyl iodide testing to a penetration less than or equal to 14 percent (applying a safety factor of 2) demonstrates the assumed accident analysis efficiencies of 70 percent for methyl iodide and 90 percent for elemental iodine. This conclusion is supported by a July 10, 2000 letter from NCS Corporation that stated "Nuclear grade activated carbon, when tested in accordance with ASTM D3803-1989 (methyl iodide...) to a penetration of 15%, is more conservative than testing the same carbon in accordance with ASTM D3803-1979 (elemental iodine...) to a penetration of 5%. ...As a general rule, you may expect the radioiodine penetration through nuclear grade activated carbon to increase from 20 to 100 times when switching from elemental iodine to methyl iodide testing." Therefore, if the efficiencies of the HEPA filters and charcoal adsorbers are as specified, at the temperatures, flow rates and velocities within the design values of the system, the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10 CFR Part 50.

The charcoal in the Control Room Filtration System is replaced with new charcoal rather than tested for continued use because the charcoal bed design does not include a provision for taking in-place charcoal samples.

5.0 DESIGN FEATURES

5.1 SITE LOCATION

The Surry Power Station is located in Surry County, Virginia, on property owned by Virginia Electric and Power Company on a point of land called Gravel Neck which juts into the James River. It is approximately 46 miles SE of Richmond, Virginia, 17 miles NW of Newport News, Virginia, and 25 miles NW of Norfolk, Virginia.

5.2 REACTOR CORE

5.2.1 Fuel Assemblies

The reactor shall contain 157 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy, ZIRLO, or Optimized ZIRLO fuel rods with an initial composition of natural or slightly enriched uranium dioxide ($U0_2$) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core locations.

5.2.2 Control Rod Assemblies

The reactor core shall contain 48 control rod assemblies. The control material shall be silver indium cadmium, as approved by the NRC.

5.3 FUEL STORAGE

5.3.1 Criticality

5.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} \leq 0.95$ if fully flooded with borated water to 350 ppm, which includes an allowance for uncertainties and biases as described in Appendix 9A of the UFSAR;

c. $k_{eff} < 1.0$ if fully flooded with unborated water, which includes an allowance for uncertainties and biases as described in Appendix 9A of the UFSAR, and;

d. A nominal 14 inch center to center distance between fuel assemblies placed in the storage racks.

5.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. Required empty cells in accordance with Figure 5.3-1, when any stored fuel has an enrichment greater than 4.35 weight percent;

c. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties and biases calculated in accordance with the methodology described in Appendix 9A of the UFSAR;

d. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties and biases calculated in accordance with the methodology described in Appendix 9A of the UFSAR; and

e. A nominal 21 inch center to center distance between fuel assemblies placed in the storage racks.

5.3.1.3 The spent fuel pool is divided into a two-region storage pool. Region 1 comprises the first three rows of fuel racks (324 storage locations) adjacent to the Fuel Building Trolley Load Block. Region 2 comprises the remainder of the fuel racks in the fuel pool. During spent fuel cask handling, Region 1 is limited to storage of spent fuel assemblies which have decayed at least 150 days after discharge and shall be restricted to those assemblies in the "acceptable" domain of Figure 5.3-2. Administrative controls with written procedures will be employed in the selection and placement of these assemblies.

5.3 FUEL STORAGE (CONTINUED)

5.3.2 Boron Concentration

Whenever there is spent fuel in the spent fuel storage pool, the pool shall be filled with borated water at a boron concentration not less than 2300 ppm to match that used in the reactor cavity and refueling canal during refueling operations.

5.3.3 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 41 feet, 2 inches mean sea level, USGS datum.

5.3.4 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1044 fuel assemblies.

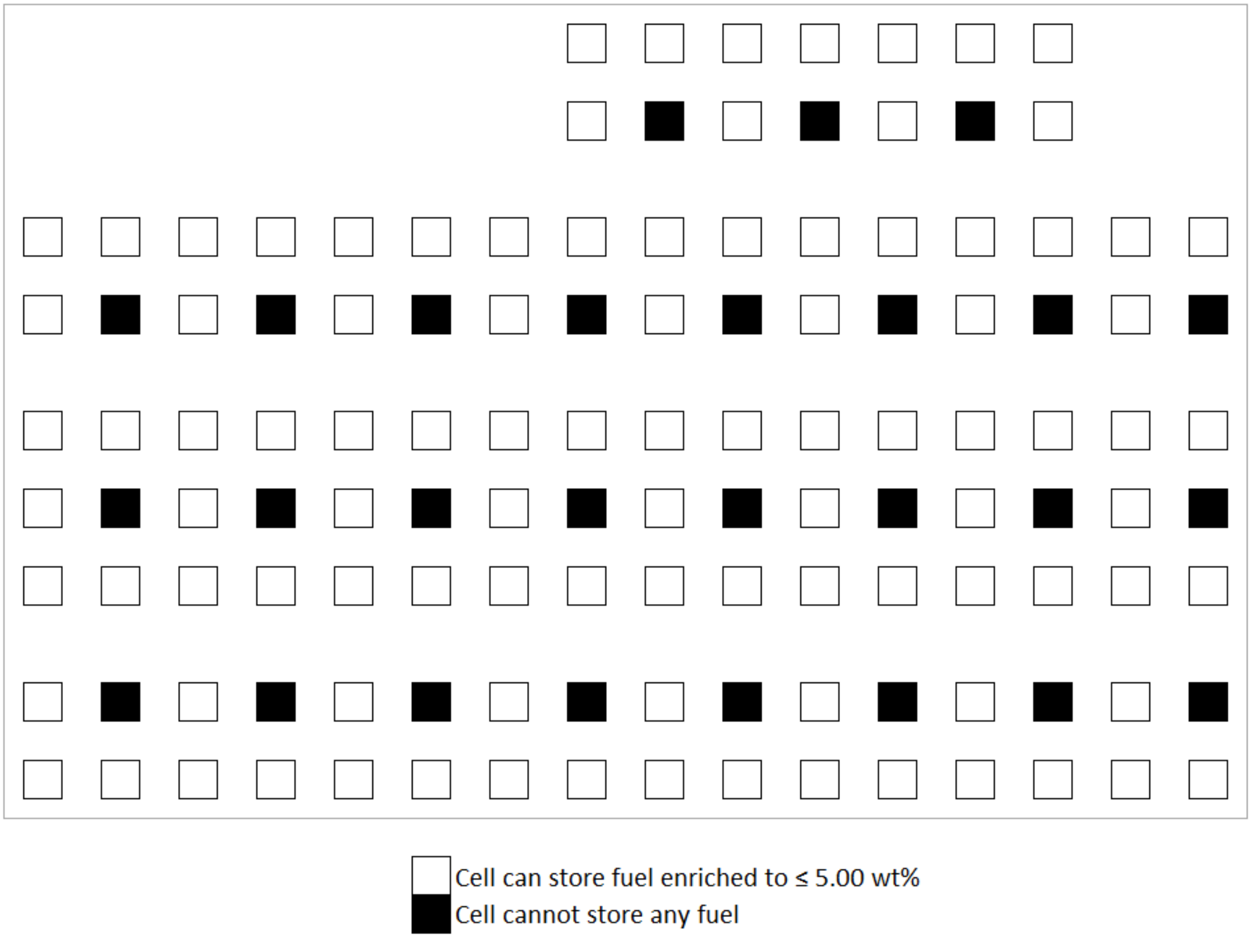

Figure 5.3-1
NEW FUEL STORAGE RACKS
REQUIRED EMPTY CELLS WHEN ANY STORED FUEL IS > 4.35 WT% U-235

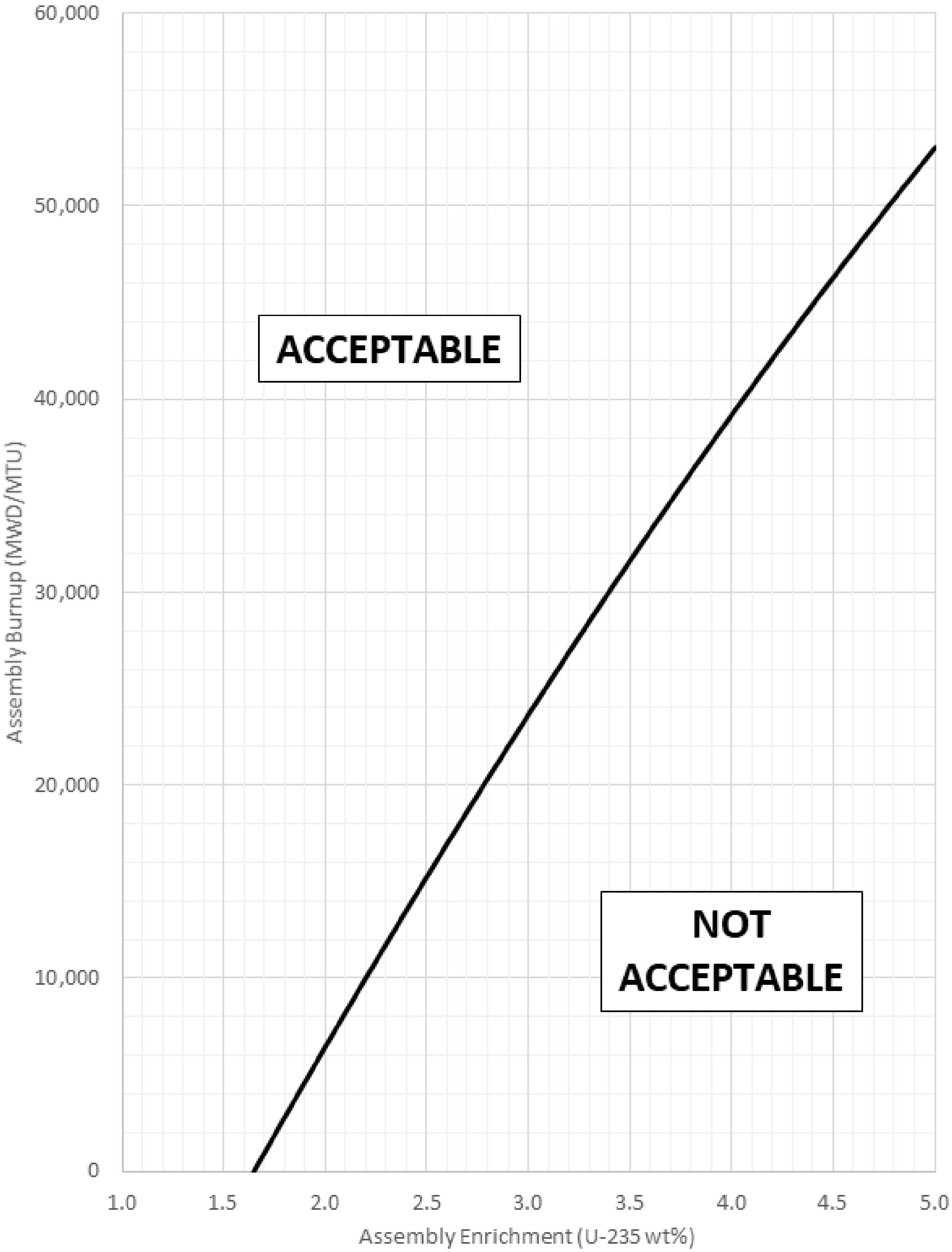

Figure 5.3-2
MINIMUM FUEL EXPOSURE VERSUS INITIAL ENRICHMENT TO PREVENT CRITICALITY IN DAMAGED RACKS

$$Required\ Burnup\ (MWD/MTU) = -849x^2 + 21470x - 33110$$

where "x" is the U-235 enrichment in wt%.

6.0 ADMINISTRATIVE CONTROLS

6.1 Responsibility, Organization and Qualifications

6.1.1 Responsibility

1. The plant manager shall be responsible for the overall unit operation. During his absence, the plant manager will delegate in writing the succession to this responsibility.

2. The Shift Manager shall be responsible for the control room command function.

6.1.2 Organization

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 the safety of the nuclear power plant.

   a. Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the QA Program. The plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be maintained in appropriate administrative documents.

   b. The plant manager shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

   c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining and providing technical support to the plant to ensure nuclear safety.

   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 independence from operating pressures.

2. Unit Staff

   The unit staff organization shall include the following:

   a. Each on-duty shift shall be composed of at least the minimum shift crew composition for each unit as shown in Table 6.1-1.

   b. A radiation protection technician 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 position.

   c. All core alterations shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator limited to fuel handling who has no other concurrent responsibilities during this operation.

   d. The operations manager shall hold (or have previously held) a Senior Reactor Operator License for Surry Power Station or a similar design Pressurized Water Reactor plant. The Superintendent Nuclear Shift Operations shall hold an active Senior Reactor Operator License for Surry Power Station.

   e. Procedures will be established to insure that NRC policy statement guidelines regarding working hours established for employees are followed. In addition, procedures will provide for documentation of authorized deviations from those guidelines and that the documentation is available for NRC review.

6.1.3 Unit Staff Qualifications

1. Each member of the unit staff shall meet or exceed the minimum qualifications referenced for comparable positions as specified in the Nuclear Facility Quality Assurance Program Description. Incumbents in the positions of Shift Manager, Unit Supervisor (SRO), Control Room Operator (RO), and the individual providing advisory technical support to the unit operations shift crew, shall meet or exceed the requirements of 10 CFR 55.59(c) and 55.31(a)(4).

2. For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator and a licensed Reactor Operator are those individuals who, in addition to meeting the requirements of TS 6.1.3.1 perform the functions described in 10 CFR 50.54(m).

TABLE 6.1-1

MINIMUM SHIFT CREW COMPOSITION

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION		
	ONE UNIT OPERATING	TWO UNITS OPERATING	TWO UNITS IN COLD SHUTDOWN OR REFUELING
SM	1	1	1
SRO	1	1	None
RO	3	3	2
AO	4	4	4
STA	1	1	None

SM - Shift Manager with a Senior Reactor Operators License.

SRO - Individual with a Senior Reactor Operators License.

RO - Individual with a Reactors Operators License.

AO - Auxiliary Operator

STA - Individual providing advisory technical support to the unit operations shift crew.

Except for the Shift Manager, the Shift Crew Composition may be one less than the minimum requirements of Table 6.1-1 for a period of time not to exceed 2 hours in order to accomodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the Shift Crew Composition to within the minimum requirements of Table 6.1-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Manager from the Control Room while the unit is in operation, an individual (other than the technical advisor) with a valid SRO license shall be designated to assume the Control Room command function. During any absence of the Shift Manager from the Control Room while the unit is shutdown or refueling, an individual with a valid SRO or RO license (other than the technical advisor) shall be designated to assume the Control Room command functions.

6.2 GENERAL NOTIFICATION AND REPORTING REQUIREMENTS

Specification

A. The following action shall be taken for Reportable Events:

A report shall be submitted pursuant to the requirements of Section 50.73 to 10 CFR.

B. Immediate notifications shall be made in accordance with Section 50.72 to 10 CFR.

C. CORE OPERATING LIMITS REPORT

Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle. Parameter limits for the following Technical Specifications are defined in the CORE OPERATING LIMITS REPORT:

1. TS 3.1.E - Moderator Temperature Coefficient
2. TS 3.12.A.1, TS 3.12.A.2 and TS 3.12.A.3 - Control Bank Insertion Limits
3. TS 3.12.B.1 and TS 3.12.B.2 - Power Distribution Limits
4. TS 3.12.F - DNB Parameters
5. TS 2.1 - Safety Limit, Reactor Core
6. TS 2.3.A.2.d - Overtemperature ΔT
7. TS 2.3.A.2.e - Overpower ΔT
8. TS Table 4.1-2A - Minimum Frequency for Equipment Tests: Item 22 - RCS Flow
9. TS 3.12.A.1.a, TS 3.12.A.2.a, TS 3.12.A.3.c and TS 3.12.G - Shutdown Margin

The analytical methods used to determine the core operating limits identified above shall be those previously reviewed and approved by the NRC, and identified below. The CORE OPERATING LIMITS REPORT will contain the complete identification for each of the TS referenced topical reports used to prepare the CORE OPERATING LIMITS REPORT (i.e., report number, title, revision, date, and any supplements). The core operating limits shall be determined so that applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided for information for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

REFERENCES

1. VEP-FRD-42-A, "Reload Nuclear Design Methodology"
2. WCAP-16009-P-A, "Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," (Westinghouse Proprietary).
3. EMF-2328(P)(A), "PWR Small Break LOCA Evaluation Model S-RELAP5 Based," as supplemented by ANP-3676P, "Surry Fuel-Vendor Independent Small Break LOCA Analysis," as approved by NRC Safety Evaluation Report dated March 19, 2021.
4. WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Report," (Westinghouse Proprietary)
5. VEP-NE-2-A, "Statistical DNBR Evaluation Methodology"
6. WCAP-16996-P-A, "Realistic LOCA Evaluation Methodology Applied to the Full Spectrum of Break Sizes (FULL SPECTRUM LOCA Methodology)," (Westinghouse Proprietary)
7. DOM-NAF-2-A, "Reactor Core Thermal-Hydraulics Using the VIPRE-D Computer Code," including Appendix B, "Qualification of the Westinghouse WRB-l CHF Correlation in the Dominion VIPRE-D Computer Code," and Appendix D, "Qualification of the ABB-NV and WLOP CHF Correlations in the Dominion VIPRE-D Computer Code"
8. WCAP-8745-P-A, "Design Bases for Thermal Overpower Delta-T and Thermal Overtemperature Delta-T Trip Function"
9. WCAP-12610-P-A and CENPD-404-P-A, Addendum 1-A, "Optimized ZIRLO," (Westinghouse Proprietary)

Section 6.3, "Action to Be Taken if a Safety Limit Is Exceeded," has been relocated, in part, to Section 2.1 and Section 2.2. Specific reporting requirements have been removed from TS.

6.4 UNIT OPERATING PROCEDURES AND PROGRAMS

Specification

A. Detailed written procedures with appropriate check-off lists and instructions shall be provided for the following conditions:

1. Normal startup, operation, and shutdown of a unit, and of all systems and components involving nuclear safety of the station.

2. Calibration and testing of instruments, components, and systems involving nuclear safety of the station.

3. Actions to be taken for specific and foreseen malfunctions of systems or components including alarms, primary system leaks and abnormal reactivity changes.

4. Release of radioactive effluents.

5. Emergency conditions involving potential or actual release of radioactivity.

6. Emergency conditions involving violation of industrial security.

7. Preventive or corrective maintenance operations which would have an effect on the safety of the reactor.

8. Refueling operations.

B. Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

1. In lieu of the "control device" or "alarm signal" required by paragraph 20.1601 of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP)*. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

   a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

   b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

   c. An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by Health Physics in the RWP.

* Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they comply with approved plant radiation protection procedures for entry into high radiation areas.

2. The requirements of 6.4.B.1 above, shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr, but less than 500 rads/hr at one meter from a radiation source or any surface through which radiation penetrates. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the Shift Manager on duty and/or the senior station individual assigned the responsibility for health physics and radiation protection.

3. Written procedures shall be established, implemented, and maintained covering the activities referenced below:

   a. Process Control Program implementation.

   b. Offsite Dose Calculation Manual implementation.

C. Deleted

D. All procedures described in Specifications 6.4.A and 6.4.B shall be followed.

E. The facility Fire Protection Program and implementing procedures which have been established for the station shall be implemented and maintained.

F. Deleted

G. Deleted

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H. Practice of site evacuation exercises shall be conducted annually, following emergency procedures and including a check of communications with off-site report groups.

I. <u>Inservice Testing Program</u>

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

1. Testing frequencies specified in the ASME Code for Operation and Maintenance of Nuclear Power Plants and applicable Addenda as follows:

ASME Code for Operation and Maintenance of Nuclear Power Plants and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Quarterly or every 3 months	At least once per 92 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days
Once per fuel cycle (18 months)	At least once per 549 days
Every cold shutdown	Every cold shutdown
Every refueling outage	Every refueling outage

2. The provisions of TS 4.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

3. The provisions of TS 4.0.3 are applicable to inservice testing activities; and

4. Nothing in the ASME Code for Operation and Maintenance of Nuclear Power Plants shall be construed to supersede the requirements of any TS.

J. <u>Technical Specifications (TS) Bases Control Program</u>

This program provides a means for processing changes to the Bases of these Technical Specifications.

1. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

2. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   a. a change in the TS incorporated in the license; or

   b. a change to the UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

3. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

4. Proposed changes that meet the criteria of Specification 6.4.J.2 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).

K. <u>Systems Integrity</u>

The licensee shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

L. <u>Iodine Monitoring</u>

The licensee shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital area under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

M. Deleted

N. Radioactive Effluent Controls Program

A program shall be provided conforming 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 (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to ten times 10 CFR 20, Appendix B, Table 2, Column 2,

3) 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,

4) 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 Appendix I to 10 CFR Part 50,

5) Determination of cumulative and projected 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,

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31-day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas at or beyond the SITE BOUNDARY shall be limited to the following:

   a) For noble gases: Less than or equal to a dose rate of 500 mrem/yr to the total body and less than or equal to a dose rate of 3000 mrem/yr to the skin, and

   b) For Iodine-131, Iodine-133, Tritium, and all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to a dose rate of 1500 mrem/yr to any organ.

8) 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 Appendix I to 10 CFR Part 50,

9) 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 greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

O. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR Part 50, and (3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM.
2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and
3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

P. Secondary Water Chemistry Monitoring Program

A secondary water chemistry monitoring program shall be provided to inhibit steam generator tube degradation. This program shall include the following:

1) Identification of a sampling schedule for the critical parameters and control points for these parameters:
2) Identification of the procedures used to quantify parameters that are critical to control points:
3) Identification of process sampling points:
4) Procedure for the recording and management of data:
5) Procedures defining corrective actions for off control point chemistry conditions: and
6) A procedure for identifying the authority responsible for the interpretation of the data, and the sequence and timing of administrative events required to initiate corrective action.

Q. Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

1. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

2. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   a. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary to secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary to secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

   b. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm for all SG.

c. The operational LEAKAGE performance criterion is specified in TS 3.1.C and 4.13, "RCS Operational LEAKAGE."

3. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth-based criteria:

   a. Tubes with service-induced flaws located greater than 17.89 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 17.89 inches below the top of the tubesheet shall be plugged upon detection.

4. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. Portions of the tube greater than 17.89 inches below the top of the tubesheet are excluded from this requirement. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of 4.a, 4.b, and 4.c below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

   a. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

b. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections).* In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in b.1, b.2, and b.3 below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

1. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

2. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

3. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

*As approved by Amendment Nos. 299 and 299, the inspection of Surry Unit 2 SG B may be deferred, on a one-time basis, from the Surry Unit 2 spring 2020 refueling outage (S2R29) to the Surry Unit 2 2021 fall refueling outage (S2R30).

c. If crack indications are found in the portions of the SG tube not excluded above, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

5. Provisions for monitoring operational primary to secondary LEAKAGE.

R. Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Habitability Program

A Main Control Room/Emergency Switchgear Room (MCR/ESGR) Envelope Habitability Program shall be established and implemented to ensure that MCR/ESGR envelope habitability is maintained such that, with an OPERABLE MCR/ESGR Emergency Ventilation System (EVS), MCR/ESGR envelope occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the MCR/ESGR envelope under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. The program shall include the following elements:

1. The definition of the MCR/ESGR envelope and the MCR/ESGR envelope boundary.
2. Requirements for maintaining the MCR/ESGR envelope boundary in its design condition including configuration control and preventive maintenance.
3. Requirements for (a) determining the unfiltered air inleakage past the MCR/ESGR envelope boundary into the MCR/ESGR envelope in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (b) assessing MCR/ESGR envelope habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

   The following is an exception to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

   - 2.C.1 Licensing Bases - Vulnerability assessments for radiological, hazardous chemical and smoke, and emergency ventilation system testing were completed as documented in the UFSAR. The exceptions to the Regulatory Guides (RGs) referenced in RG 1.196 (i.e., RG 1.52, RG 1.78 and RG 1.183), which were considered in completing the vulnerability assessments, are documented in the UFSAR/current licensing basis. Compliance with these RGs is consistent with the current licensing basis as described in the UFSAR.

4. Measurement, at designated locations, of the MCR/ESGR envelope pressure relative to all external areas adjacent to the MCR/ESGR envelope boundary during the pressurization mode of operation by one train of the MCR/ESGR EVS, operating at the flow rate required by TS 4.20, at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the assessment of the MCR/ESGR envelope boundary.
5. The quantitative limits on unfiltered air inleakage into the MCR/ESGR envelope. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph 3. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of MCR/ESGR envelope occupants to these hazards will be within the assumptions in the licensing basis.
6. The provisions of SR 4.0.2 are applicable to the Frequencies for assessing MCR/ESGR envelope habitability, determining MCR/ESGR envelope unfiltered inleakage, and measuring MCR/ESGR envelope pressure and assessing the MCR/ESGR envelope boundary as required by paragraphs 3 and 4, respectively.

S. <u>Surveillance Frequency Control Program (SFCP)</u>

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specification are performed at interval sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 4.0.2 and 4.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

T. <u>Inservice Examination, Testing, and Service Life Monitoring Program for Snubbers</u>

This program conforms to the examination, testing, and service life monitoring for dynamic restraints (snubbers) in accordance with 10 CFR 50.55a inservice inspection (ISI) requirements for supports. The program shall be in accordance with the following:

a. This program shall meet 10 CFR 50.55a(g) requirements for supports.

b. The program shall meet the requirements of ISI of supports set forth in subsequent edition of the Code of Record and addenda of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (BPV) Code and the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code) that are incorporated by reference in 10 CFR 50.55a(b), subject to its limitations and modifications, and subject to Commission approval.

c. The program shall, as allowed by 10 CFR 50.55a(b)(3)(V), meet Subsection ISTA, "General Requirements," and Subsection ISTD, "Preservice and Inservice Examination and Testing of Dynamic Restraints (Snubbers) in Light-Water Reactor Nuclear Power Plants," in lieu of Section XI of the ASME BPV Code ISI requirements for snubbers, or meet authorized alternatives pursuant to 10 CFR 50.55a(a)(3).

d. The 120-month program updates shall be made in accordance with 10 CFR 50.55a (including 10 CFR 50.55a(b)(3)(V)) subject to the limitations and modifications listed therein.

U. Augmented Inspections and Examinations

The following augmented inspections and examinations have been relocated from the Technical Specifications to the Technical Requirements Manual (TRM):

a. Augmented Inspections - Inservice inspections augmenting those required by ASME Section XI shall be performed to provide the additional assurance necessary for continued integrity of important components involved in safety and plant operation (e.g., the low head safety injection piping in the valve pit, the low pressure turbine blades, and sensitized stainless steel).

b. Augmented Inservice Inspection of High Energy Lines Outside of Containment - In accordance with the Augmented Inservice Inspection Program for High Energy Lines Outside of Containment, examinations of welds in the main steam and main feedwater lines in the main steam valve house of each unit shall be performed to provide assurance of the continued integrity of the piping systems over their service lifetime. These requirements apply to welds in piping systems or portions of systems located outside of containment where protection from the consequences of postulated ruptures is not provided by a system of pipe whip restraints, jet impingement barriers, protective enclosures and/or other measures designed specifically to cope with such ruptures.

Section 6.5, "Station Operating Records," has been relocated to the Operational Quality Assurance Program, and Pages TS 6.5-2 and TS 6.5-3 have been deleted in their entirety.

6.6 STATION REPORTING REQUIREMENTS

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following identified reports shall be submitted to the Administrator of the appropriate NRC Regional Office unless otherwise noted.

A. Routine Reports

1. Startup Report

A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the tests identified in the FSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any addditional specific details required in license conditions based on other commitments shall be included in this report.

Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial power operations), supplementary reports shall be submitted at least every 3 months until all three events have been completed.

2. Annual Reports[1]

   a. deleted

Note: Footnotes 1 and 2 are located on page TS 6.6-11.

b. Deleted

3. Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each degradation mechanism,

f. The number and percentage of tubes plugged to date, and the effective plugging percentage in each steam generator.

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. The primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. The calculated accident induced LEAKAGE rate from the portion of the tubes below 17.89 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 1.80 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined, and

j. The results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

Pages 6.6-4 through 6.6-9 have been deleted.

B. Unique Reporting Requirements

1. Inservice Inspection Evaluation

Special summary technical report shall be submitted to the Director of Reactor Licensing, Office of Nuclear Reactor Regulation, NRC, Washington, D.C. 20555, after 5 years of operation. This report shall include an evaluation of the results of the inservice inspection program and will be reviewed in light of the technology available at that time.

2. Annual Radiological Environment Operating Report[1]

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The report shall include summaries, interpretations, and analysis 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 (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR Part 50.

3. Annual Radioactive Effluent Release Report[3]

The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

C. Special Reports

In the event that the Reactor Vessel Overpressure Mitigating System is used to mitigate a RCS pressure transient, submit a Special Report to the Commission within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or the administrative controls on the transient and any corrective action necessary to prevent recurrence.

FOOTNOTES

1. A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2. This tabulation supplements the requirements of Section 20.2206 of 10 CFR Part 20.

3. A single submittal may be made for a multi-unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

6.7 Environmental Qualifications

A. By no later than June 30, 1982 all safety-related electrical equipment in the facility shall be qualified in accordance with the provisions of: Division of Operating Reactors "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines); or, NUREG-0588 "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," December 1979. Copies of these documents are attached to Order for Modification of Licence Nos. DPR-32 and DPR-37 dated October 24, 1980.

B. By no later than December 1, 1980, complete and auditible records must be available and maintained at a central location which describe the environmental qualification method used for all safety-related electrical equipment in sufficient details to document the degree of compliance with the DOR Guidelines or NUREG-0588. Thereafter, such records should be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.8 PROCESS CONTROL PROGRAM AND OFFSITE DOSE CALCULATION MANUAL

A. Process Control Program (PCP)

Changes to the PCP:

1. Shall be documented and records of reviews performed shall be retained as required by the Operational Quality Assurance Program Topical Report. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

   b. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall require the approval of the plant manager prior to implementation.

B. Offsite Dose Calculation Manual (ODCM)

Changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained as required by the Operational Quality Assurance Program Topical Report. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

b. A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

2. Shall require the approval of the plant manager prior to implementation.

3. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.