Byron Nuclear Station

Technical Specification Bases

(TS Bases)

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

B 3.1 REACTIVITY CONTROL SYSTEMS (continued)

B 3.3	INSTRUMENTATION (continued)	
	B 3.3.9-1	Revision 17
	B 3.3.9-2	Revision 17
	B 3.3.9-3	Revision 17
	B 3.3.9-4	Revision 75
	B 3.3.9-5	Revision 75
	B 3.3.9-6	Revision 75
	B 3.3.9-7	Revision 75
	B 3.3.9-8	Revision 17
B 3.4	REACTOR COOLANT SYSTEM (RCS)	
	B 3.4.1-1	Revision 0
	B 3.4.1-2	Revision 85
	B 3.4.1-3	Revision 18
	B 3.4.1-4	Revision 75
	B 3.4.1-5	Revision 75
	B 3.4.1-6	Revision 18
	B 3.4.2-1	Revision 0
	B 3.4.2-2	Revision 0
	B 3.4.2-3	Revision 75
	B 3.4.2-4	Revision 0
	B 3.4.3-1	Revision 0
	B 3.4.3-2	Revision 0
	B 3.4.3-3	Revision 0
	B 3.4.3-4	Revision 0
	B 3.4.3-5	Revision 0
	B 3.4.3-6	Revision 0
	B 3.4.3-7	Revision 0
	B 3.4.3-8	Revision 75
	B 3.4.4-1	Revision 0
	B 3.4.4-2	Revision 0
	B 3.4.4-3	Revision 58
	B 3.4.4-4	Revision 0
	B 3.4.4-5	Revision 75
	B 3.4.4-6	Revision 0
	B 3.4.5-1	Revision 0
	B 3.4.5-2	Revision 0
	B 3.4.5-3	Revision 0
	B 3.4.5-4	Revision 58
	B 3.4.5-5	Revision 0
	B 3.4.5-6	Revision 0
	B 3.4.5-7	Revision 75
	B 3.4.5-8	Revision 75
	B 3.4.6-1	Revision 0
	B 3.4.6-2	Revision 0
	B 3.4.6-3	Revision 96
	B 3.4.6-4	Revision 0
	B 3.4.6-5	Revision 96
	B 3.4.6-6	Revision 96

B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)

B 3.4.6-7	Revision 96
B 3.4.6-8	Revision 96
B 3.4.7-1	Revision 0
B 3.4.7-2	Revision 0
B 3.4.7-3	Revision 96
B 3.4.7-4	Revision 0
B 3.4.7-5	Revision 75
B 3.4.7-6	Revision 96
B 3.4.7-7	Revision 96
B 3.4.7-8	Revision 96
B 3.4.8-1	Revision 0
B 3.4.8-2	Revision 96
B 3.4.8-3	Revision 0
B 3.4.8-4	Revision 96
B 3.4.8-5	Revision 96
B 3.4.8-6	Revision 96
B 3.4.9-1	Revision 0
B 3.4.9-2	Revision 84
B 3.4.9-3	Revision 0
B 3.4.9-4	Revision 0
B 3.4.9-5	Revision 75
B 3.4.9-6	Revision 75
B 3.4.10-1	Revision 50
B 3.4.10-2	Revision 0
B 3.4.10-3	Revision 50
B 3.4.10-4	Revision 102
B 3.4.10-5	Revision 63
B 3.4.10-6	Revision 0
B 3.4.11-1	Revision 0
B 3.4.11-2	Revision 0
B 3.4.11-3	Revision 0
B 3.4.11-4	Revision 48
B 3.4.11-5	Revision 115
B 3.4.11-6	Revision 115
B 3.4.11-7	Revision 0
B 3.4.11-8	Revision 75
B 3.4.11-9	Revision 75
B 3.4.11-10	Revision 0
B 3.4.12-1	Revision 0
B 3.4.12-2	Revision 0
B 3.4.12-3	Revision 0
B 3.4.12-4	Revision 0
B 3.4.12-5	Revision 0
B 3.4.12-6	Revision 0
B 3.4.12-7	Revision 0
B 3.4.12-8	Revision 0
B 3.4.12-9	Revision 76
B 3.4.12-10	Revision 0

B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)

B 3.4.12-11	Revision 48
B 3.4.12-12	Revision 0
B 3.4.12-13	Revision 0
B 3.4.12-14	Revision 75
B 3.4.12-15	Revision 102
B 3.4.12-16	Revision 75
B 3.4.12-17	Revision 75
B 3.4.12-18	Revision 0
B 3.4.13-1	Revision 0
B 3.4.13-2	Revision 59
B 3.4.13-3	Revision 59
B 3.4.13-4	Revision 59
B 3.4.13-5	Revision 58
B 3.4.13-6	Revision 58
B 3.4.13-7	Revision 75
B 3.4.13-8	Revision 75
B 3.4.14-1	Revision 0
B 3.4.14-2	Revision 0
B 3.4.14-3	Revision 0
B 3.4.14-4	Revision 0
B 3.4.14-5	Revision 0
B 3.4.14-6	Revision 75
B 3.4.14-7	Revision 0
B 3.4.14-8	Revision 75
B 3.4.15-1	Revision 91
B 3.4.15-2	Revision 91
B 3.4.15-3	Revision 91
B 3.4.15-4	Revision 91
B 3.4.15-5	Revision 91
B 3.4.15-6	Revision 91
B 3.4.15-7	Revision 91
B 3.4.15-8	Revision 91
B 3.4.16-1	Revision 72
B 3.4.16-2	Revision 72
B 3.4.16-3	Revision 72
B 3.4.16-4	Revision 72
B 3.4.16-5	Revision 75
B 3.4.16-6	Revision 75
B 3.4.17-1	Revision 0
B 3.4.17-2	Revision 0
B 3.4.17-3	Revision 0
B 3.4.17-4	Revision 0
B 3.4.17-5	Revision 75
B 3.4.17-6	Revision 0
B 3.4.18-1	Revision 0
B 3.4.18-2	Revision 0
B 3.4.18-3	Revision 0
B 3.4.18-4	Revision 0

B 3.6	CONTAINMENT SYSTEMS (continued)	
	B 3.6.3-26	Revision 105
	B 3.6.3-27	Revision 78
	B 3.6.3-28	Revision 17
	B 3.6.3-29	Revision 68
	B 3.6.3-30	Revision 1
	B 3.6.4-1	Revision 0
	B 3.6.4-2	Revision 18
	B 3.6.4-3	Revision 0
	B 3.6.4-4	Revision 75
	B 3.6.5-1	Revision 0
	B 3.6.5-2	Revision 85
	B 3.6.5-3	Revision 0
	B 3.6.5-4	Revision 75
	B 3.6.6-1	Revision 55
	B 3.6.6-2	Revision 101
	B 3.6.6-3	Revision 0
	B 3.6.6-4	Revision 0
	B 3.6.6-5	Revision 85
	B 3.6.6-6	Revision 96
	B 3.6.6-7	Revision 114
	B 3.6.6-8	Revision 114
	B 3.6.6-9	Revision 96
	B 3.6.6-10	Revision 102
	B 3.6.6-11	Revision 96
	B 3.6.6-12	Revision 96
	B 3.6.6-13	Revision 96
	B 3.6.6-14	Revision 96
	B 3.6.7-1	Revision 101
	B 3.6.7-2	Revision 101
	B 3.6.7-3	Revision 101
	B 3.6.7-4	Revision 75
	B 3.6.7-5	Revision 101
	B 3.6.7-6	Revision 101
	B 3.6.8-1	Revision 117
	B 3.6.8-2	Revision 117
	B 3.6.8-3	Revision 117
	B 3.6.8-4	Revision 117
	B 3.6.8-5	Revision 117
	B 3.6.8-6	Revision 117
B 3.7	PLANT SYSTEMS	
	B 3.7.1-1	Revision 34
	B 3.7.1-2	Revision 34
	B 3.7.1-3	Revision 102
	B 3.7.1-4	Revision 34
	B 3.7.1-5	Revision 85
	B 3.7.1-6	Revision 102
	B 3.7.1-7	Revision 63

B 3.7 PLANT SYSTEMS (continued)

TABLE OF CONTENTS - TECHNICAL SPECIFICATION BASES TABLES

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and Anticipated Operational Occurrences (AOOs). This is accomplished by having a Departure from Nucleate Boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak Linear Heat Rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and Main Steam Safety Valves (MSSVs) prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability that the hot fuel pellet in the core must not experience centerline fuel melting; and

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

The Reactor Trip System setpoints (Ref. 2) specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation," in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) highest loop average temperature, pressurizer pressure, RCS flow, Axial Flux Difference (AFD), and THERMAL POWER level that would result in a Departure from Nucleate Boiling Ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Automatic preservation of these reactor core SLs is provided by the appropriate operation of the RPS and the MSSVs (Ref. 2).

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The figure in the COLR shows the reactor core limits 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 core exit quality is within the limits defined by the DNBR correlation.

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

a. There must be at least 95% probability that the hot fuel pellet in the core must not experience centerline fuel melting; and

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

BASES

SAFETY LIMITS (continued)

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and AOOs. To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature ΔT 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 and the MSSVs ensure that for variations in the RCS average temperature, pressurizer pressure, RCS flow, AFD, and THERMAL POWER that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The MSSVs or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1. In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMITS VIOLATIONS

If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. UFSAR, Section 7.2.

This page intentionally left blank.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the Reactor Coolant Pressure Boundary (RCPB) design conditions are not to be exceeded during normal operation and Anticipated Operational Occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2500 psia. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with SECTION III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components are pressure tested, in accordance with the requirements of the approved ISI/IST Program which is based on ASME Code, SECTION XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 50.67, “Accident Source Term," (Ref. 4). If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

BASES

APPLICABLE SAFETY ANALYSES

The pressurizer safety valves, the Main Steam Safety Valves (MSSVs), and the Pressurizer Pressure-High trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in SECTION III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the MSSVs are assumed to open when the steam pressure reaches the safety valve settings, and nominal feedwater supply is maintained (Ref. 5).

The Reactor Trip System setpoints, together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The Pressurizer Pressure-High trip setpoint is specifically set to provide protection against overpressurization (Ref. 6). The safety analyses for both the high pressure trip and the pressurizer safety valves are performed using conservative assumptions relative to pressure control devices (Ref. 5).

More specifically, no credit is taken for operation of the following:

a. Pressurizer power operated relief valves;

b. Steam Generator (SG) power operated relief valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valves.

BASES

SAFETY LIMITS	The maximum transient pressure allowed in the RCS pressure vessel, pressurizer, and the RCS piping, valves, and fittings under the ASME Code, SECTION III, is 110% of design pressure. Therefore, the SL on maximum allowable RCS pressure is 2735 psig.
APPLICABILITY	SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.
SAFETY LIMIT VIOLATIONS	If SL 2.1.2, "RCS Pressure SL," is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour. Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the Completion Time is exceeded, actions shall continue in order to restore compliance with the SL and bring the unit to MODE 3.

BASES

SAFETY LIMIT VIOLATIONS (continued)

If SL 2.1.2 is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. If the Completion Time is exceeded, actions shall continue in order to reduce pressure to less than the SL. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14, GDC 15, and GDC 28.
2. ASME, Boiler and Pressure Vessel Code, SECTION III, Article NB-7000.
3. ASME, Boiler and Pressure Vessel Code, SECTION XI.
4. 10 CFR 50.67.
5. UFSAR, Section 5.2.2.
6. UFSAR, Section 7.2.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.10 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered, unless otherwise specified. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

BASES

LCO 3.0.2 (continued)

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. In this instance, the individual LCO's ACTIONS specify the Required Actions. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

BASES

LCO 3.0.2 (continued)

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4). Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable and the new LCO is not met. In this case, the Completion Times of the new Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

BASES

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no single Condition or combination of Conditions stated in the ACTIONS can be made that corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted. In such cases, the Conditions corresponding to such combinations state that LCO 3.0.3 shall be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to enter lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a unit upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

LCO 3.0.3 (continued)

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. The LCO is no longer applicable.

c. A Condition exists for which the Required Actions have now been performed.

d. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours from MODE 1, 2, 3, or 4 for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for entering the next lower MODE applies. If a lower MODE is entered in less time than allowed, however, the total allowable time to enter MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is entered in 2 hours, then the time allowed for entering MODE 4 is the next 11 hours, because the total time for entering MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to enter a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

BASES

LCO 3.0.3 (continued)

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.14, "Spent Fuel Pool Water Level." LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in the spent fuel pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with either LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered following entry into the MODE or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified

BASES

LCO 3.0.4 (continued)

condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed in the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4 (b), must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed

BASES

LCO 3.0.4 (continued)

MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these system and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., reactor coolant system specific activity), and may be applied to other Specifications based on NRC plant-specific approval.

BASES

LCO 3.0.4 (continued)

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

BASES

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this LCO is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

Another example of demonstrating equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel.

BASES

LCO 3.0.5 (continued)

Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition 1) to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions. This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

BASES

LCO 3.0.6 (continued)

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.15, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

BASES

LCO 3.0.7	There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Exception LCOs (e.g., LCO 3.1.8, "PHYSICS TESTS Exceptions-MODE 2") allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect. The Applicability of an Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Exception LCO, the requirements of the Exception LCO shall be followed.
LCO 3.0.8	LCO 3.0.8 establishes the applicability of each Specification to both Unit 1 and Unit 2 operation. Whenever a requirement applies to only one unit, or is different for each unit, this will be identified in the appropriate section of the Specification (e.g., Applicability, Surveillance, etc.) with parenthetical reference, Notes, or other appropriate presentation within the body of the requirement.
LCO 3.0.9	LCO 3.0.9 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the

BASES

LCO 3.0.9 (continued)

Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

When applying LCO 3.0.9.a, at least one train of Auxiliary Feedwater (AFW) system must be OPERABLE during MODES when AFW is required to be OPERABLE. When applying LCO 3.0.9.a during MODES when AFW is not required to be OPERABLE, a core cooling method (such as the Residual Heat Removal (RHR) system) must be available per applicable site procedures. When applying LCO 3.0.9.b, a means of core cooling must remain available (AFW, RHR, equipment necessary for feed and bleed operations, etc.). Reliance on availability of a core cooling source during modes where AFW is not required by TS provides an equivalent safety margin for plant operations were LCO 3.0.9 not applied and meets the intent of Technical Specifications Task Force Change Traveler TSTF-372, Revision 4, "Addition of LCO 3.0.8, Inoperability of Snubbers."

When a snubber is to be rendered incapable of performing its related support function (i.e., nonfunctional) for testing or maintenance or is discovered to not be functional, it must be determined whether any system(s) require the affected snubber(s) for system OPERABILITY, and whether the plant is in a MODE or specified condition in the Applicability that requires the supported system(s) to be OPERABLE.

If an analysis determines that the supported system(s) do not require the snubber(s) to be functional in order to support the OPERABILITY of the system(s), LCO 3.0.9 is not needed. If the LCO(s) associated with any supported system(s) are not currently applicable (i.e., the plant is not in a MODE or other specified condition in the Applicability of the LCO), LCO 3.0.9 is not needed. If the supported system(s) are inoperable for reasons other than snubbers, LCO 3.0.9 cannot be used. LCO 3.0.9 is an allowance, not a requirement. When a snubber is nonfunctional, any supported system(s) may be declared inoperable instead of using LCO 3.0.9.

Every time the provisions of LCO 3.0.9 are used, the station will confirm that at least one train (or subsystem) of systems supported by the inoperable snubbers will remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. A record of the design function of the inoperable

BASES

LCO 3.0.9 (continued)

snubber (i.e., seismic vs. non-seismic) and the associated plant configuration will be available on a recoverable basis for NRC staff inspection.

LCO 3.0.9 does not apply to non-seismic snubbers. The provisions of LCO 3.0.9 are not to be applied to supported TS systems unless the supported systems would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. The risk impact of dynamic loadings other than seismic loads was not assessed as part of the development of LCO 3.0.9. These shock-type loads include thrust loads, blowdown loads, water-hammer loads, steam-hammer loads, LOCA loads and pipe rupture loads. However, there are some important distinctions between non-seismic (shock-type) loads and seismic loads which indicate that, in general, the risk impact of the out-of-service snubbers is smaller for non-seismic loads than for seismic loads. First, while a seismic load affects the entire plant, the impact of a non-seismic load is localized to a certain system or area of the plant. Second, although non-seismic shock loads may be higher in total force and the impact could be as much or more than seismic loads, generally they are of much shorter duration than seismic loads. Third, the impact of non-seismic loads is more plant specific, and thus harder to analyze generically, than for seismic loads. For these reasons, every time LCO 3.0.9 is applied, at least one train of each system that is supported by the inoperable snubber(s) should remain capable of performing their required safety or support functions for postulated design loads other than seismic loads.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.9.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.9.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not

BASES

LCO 3.0.9 (continued)

capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.9.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.9.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.9 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.9 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.10

LCO 3.0.10 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions LCO 3.0.10 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made

BASES

LCO 3.0.10 (continued)

unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABLILTY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001)

The provisions of LCO 3.0.10 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions ,and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that

BASES

LCO 3.0.10 (continued)

barriers are unable to perform their related support function(s).

LCO 3.0.10 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.10 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

If during the time that LCO 3.0.10 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs	SR 3.0.1 through SR 3.0.5 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated. SR 3.0.2 and SR 3.0.3 apply in Chapter 5 only when invoked by a Chapter 5 Specification.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO 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 3.0.2, constitutes a failure to meet an LCO.

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 MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with an Exception LCO are only applicable when the Exception LCO 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 MODE or other specified condition.

BASES

SR 3.0.1 (continued)

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, 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 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers unit operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is the Containment Leakage Rate Testing Program. The requirements of regulations take precedence over the TS. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

BASES

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed 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 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with Required Actions or other remedial measures that might preclude performance 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 MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 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 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

BASES

SR 3.0.3 (continued)

SR 3.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 3.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performances of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

BASES

SR 3.0.3 (continued)

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 Completion Times of the Required Actions 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 Completion Times of the Required Actions 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 Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

BASES

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result

BASES

SR 3.0.4 (continued)

from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO’s Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

SR 3.0.5

SR 3.0.5 establishes the applicability of each Surveillance to both Unit 1 and Unit 2 operation. Whenever a requirement applies to only one unit, or is different for each unit, this will be identified with parenthetical reference, Notes, or other appropriate presentation within the SR.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and Anticipated Operational Occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion of all shutdown and control rods, assuming that the single Rod Cluster Control Assembly (RCCA) of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable RCCAs and soluble boric acid in the Reactor Coolant System (RCS). The Rod Control System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Rod Control System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The Chemical and Volume Control System can control the soluble boron concentration to compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in the safety analyses. The safety analysis establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on a reactor trip.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are not exceeded. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Accidents;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (Departure from Nucleate Boiling Ratio (DNBR)); and fuel centerline temperature limits for AOOs; and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a Main Steam Line Break (MSLB) at zero power with no decay heat, as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected Steam Generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a double ended break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

APPLICABLE SAFETY ANALYSES (continued)

For MODE 5, the primary safety analysis that relies on the SDM limits is the boron dilution analysis. In the boron dilution analysis (Ref. 3), the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

In addition to the limiting MSLB and boron dilution transients, the SDM requirement must also protect against:

a. An uncontrolled RCCA bank withdrawal condition; and

b. RCCA ejection accidents.

Each of these events is discussed below.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled RCCA withdrawal transient is terminated by a high neutron flux, high pressurizer pressure, high pressurizer water level, OTΔT, or OPΔT reactor trip (Ref. 4 and Ref. 5). In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The ejection of an RCCA (Ref. 6) rapidly adds positive reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of an RCCA also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

BASES

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 50.67, "Accident Source Term," limits (Ref. 7). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank or the refueling water storage tank. The operator should borate with the best source available for the unit conditions.

BASES

ACTIONS (continued)

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of life when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 30 gpm, it is possible to increase the boron concentration of the RCS by 123 ppm in approximately 74 minutes assuming a 7000 ppm boric acid solution. If a boron worth of 8.12 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 30 gpm and 7000 ppm represent typical values and are provided for the purpose of offering a specific example.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODE 2 with k_{eff} < 1.0 and MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal Temperature Coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS. The SDM limits are specified in the COLR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. UFSAR, Section 15.1.5.
3. UFSAR, Section 15.4.6.
4. UFSAR, Section 15.4.1.
5. UFSAR, Section 15.4.2.
6. UFSAR, Section 15.4.8.
7. 10 CFR 50.67.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of Shutdown Margin (SDM) or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed or stable (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

BASES

BACKGROUND (continued)

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RATED THERMAL POWER (RTP) and normal operating temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at Beginning Of Life (BOL) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOL, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOL, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOL conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

BASES

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

BASES

ACTIONS (continued)

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 after each refueling as an initial check on core conditions and design calculations at BOL.

SR 3.1.2.2

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The SR is modified by two Notes. Note 1 states that the SR is only required to be performed after 60 EFPD. Note 2 indicates that the normalization of predicted core reactivity to the measured value may take place within the first 60 EFPD after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.

2. UFSAR, Chapter 15.

This page intentionally left blank.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at Beginning Of Life (BOL) within the range analyzed in the plant accident analysis. The End Of Life (EOL) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOL limit.

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the UFSAR accident and transient analyses.

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

Additionally, the limitation on MTC also ensures that the Anticipated Transient Without Scram (ATWS) risk is acceptable. A cycle specific Unfavorable Exposure Time (UET) value will be calculated to ensure < 5% of the cycle operations occur when the reactivity feedback is not sufficient to prevent exceeding an ATWS overpressurization condition of ≥ 3200 psig in the RCS. This UET value will be updated for each core reload and appropriately considers the effects of changes in MTC, including any variations that are more adverse than those originally modeled in the analyses supporting the basis for the final ATWS rule.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 2 contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOL or EOL. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOL and EOL. An EOL measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOL value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

BASES

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, All Rods Out (ARO), hot zero power conditions. At EOL the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOL and EOL on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOL positive limit and the EOL negative limit are established in the COLR to allow specifying limits for each particular cycle. The COLR typically imposes a more restrictive upper limit than the bounding value of Figure 3.1.3-1. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

BASES

APPLICABILITY (continued)

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled Rod Cluster Control Assembly (RCCA) withdrawal accident) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOL MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. These withdrawal limits shall be in addition to the insertion limits of LCO 3.1.6, "Control Bank Insertion Limits." The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required control bank withdrawal limits.

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

BASES

ACTIONS (continued)

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOL MTC limit means that the safety analysis assumptions for the EOL accidents that use a bounding negative MTC value may be invalid. If the EOL MTC limit is exceeded, the unit must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time of 12 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Entry into the MODEs or other specified conditions (i.e., MODE 2 with $k_{eff} \geq 1.0$) is acceptable provided MTC is required to be within the upper limit prior to entering MODE 1. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The BOL MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In a similar fashion, the LCO demands that the MTC be less negative than the specified value for EOL full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOL LCO limit. The 300 ppm SR value is sufficiently less negative than the EOL LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

The SR is modified by three Notes. Note 1 indicates that the SR is not required to be performed until 7 Effective Full Power Days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. Note 2 indicates that if the 300 ppm Surveillance limit is exceeded, it is possible that the EOL limit on MTC could be reached before the planned EOL. Because the MTC changes slowly with core depletion, the Frequency of 14 EFPD is sufficient to avoid exceeding the EOL limit. Note 3 indicates that the Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOL limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 11.

2. UFSAR, Chapter 15.

3. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control or shutdown rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking due to the asymmetric reactivity distribution, and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod Cluster Control Assemblies (RCCAs), or rods, are moved by their Control Rod Drive Mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

BASES

BACKGROUND (continued)

The 53 RCCAs are divided among four control banks and five shutdown banks. A bank of RCCAs consists of either one group, or, two groups that are moved in a staggered fashion to provide for precise reactivity control but which are always within one step of each other. Each of the control banks are divided into two groups, for a total of 25 control bank rods. Shutdown banks A and B are also divided into two groups, however, shutdown banks C, D and E have only one group each, for a total of 28 shutdown bank rods. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the fully withdrawn position, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step 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 counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch) but not very reliable because it is a demanded position indication, not an actual position indication. For example, if a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is six steps. To increase the reliability of the system, the inductive coils are connected alternately to Data Channel A or Data Channel B. Thus, if one data channel fails, the DRPI system can be placed in "half accuracy" mode with an effective coil spacing of 7.5 inches, which is 12 steps. Therefore, the design indication accuracy of the DRPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

BASES

APPLICABLE SAFETY ANALYSES

Rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing rod inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue (i.e., statically misaligned RCCA). This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 4). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case with control bank D inserted to its full power insertion limit and one RCCA fully withdrawn. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA fully withdrawn (Ref. 5).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local Linear Heat Rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements (i.e. trippability to meet SDM) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required rod drop time assumed in the safety analysis. Rod control malfunctions that result in the inability to move rods (e.g. rod urgent failures), but do not impact trippability, do not result in rod inoperability provided proper alignment.

BASES

LCO (continued)

The requirement to maintain individual indicated rod positions within 12 steps of their group step counter demand position is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are fully inserted and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements for MODE 6.

BASES

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (i.e., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value specified in the COLR, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating boration to restore SDM to within limit.

In this situation, SDM verification must account for the worth of the untrippable rod(s), as well as the rod of maximum worth.

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the unit must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1.1 and B.1.2

When a rod becomes misaligned, it can usually be moved and is still trippable.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

BASES

ACTIONS (continued)

However, in many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be fully inserted and control bank C must be partially inserted.

With a misaligned rod, SDM must be verified to be within limit (specified in the COLR) or boration must be initiated to restore SDM to within limit.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour.

The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration to restore SDM to within limit.

B.2, B.3, B.4, and B.5

For continued operation with a misaligned rod, THERMAL POWER must be reduced when Power Distribution Monitoring System (PDMS) is inoperable, SDM must periodically be verified within limits (specified in the COLR), hot channel factors ($F_Q(Z)$ and ($F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP when PDMS is inoperable, ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 4). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. One rod is not within alignment limit; and

b. PDMS is inoperable.

BASES

ACTIONS (continued)

Discovering one rod not within alignment limit coincident with PDMS inoperable results in starting the Completion Time for the Required Action. During power operation when PDMS is OPERABLE, LHR is measured continuously. Therefore, a reduction of power to 75% RTP is not necessary to ensure that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation, at ≤ 75% RTP with PDMS inoperable and > 75% RTP with PDMS OPERABLE, with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain the core power distribution using the incore flux mapping system or PDMS and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Accident for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

Accident analyses (Ref. 3) requiring re-evaluation for continued operation with a misaligned rod include:

1. Increase in heat removal by the secondary system:

    a. Excessive increase in secondary steam flow,

    b. Inadvertent opening of a steam generator power operated relief or safety valve, and

    c. Steam system piping failure;

BASES

ACTIONS (continued)

2. Uncontrolled RCCA bank withdrawal at power;

3. RCCA misoperation:

   a. One or more dropped RCCAs within the same group,

   b. A dropped RCCA bank,

   c. Statically misaligned RCCA, and

   d. Withdrawal of a single RCCA;

4. RCCA ejection accidents; and

5. Loss of coolant accidents resulting from postulated piping breaks within the reactor coolant pressure boundary.

C.1.1 and C.1.2

More than one rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM (specified in the COLR) must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

BASES

ACTIONS (continued)

C.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement when PDMS is inoperable, the unit conditions may fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. More than one rod is not within alignment limit; and

b. PDMS is inoperable.

Discovering more than one rod not within alignment limit coincident with PDMS inoperable results in starting the Completion Time for the Required Action.

C.3

If more than one rod is found to be misaligned or becomes misaligned because of bank movement when PDMS is OPERABLE, operation may continue in Condition C for a period that should not exceed 72 hours. The allowed Completion Time is reasonable, based on the available information on power distributions (Ref. 6). This Required Action is modified by a Note that requires the performance of Required Action C.3 only when PDMS is OPERABLE.

BASES

ACTIONS (continued)

D.1

When Required Actions of Condition B or C.3 cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that the position of individual rods is within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. When a rod’s alignment cannot be verified due to a DRPI failure, the position of the rod can be determined by use of the movable incore detectors and/or PDMS. The position of the rod may be determined from the difference between the measured core power distribution and the core power distribution expected to exist based on the position of the rod indicated by the group step counter demand position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a note that permits it to not be performed for rods associated with an inoperable demand position indicator or an inoperable rod position indicator. The alignment limit is based on the demand position indicator which is not available if the indicator is inoperable. LCO 3.1.7, "Rod Position Indication," provides Actions to verify the rods are in alignment when one or more rod position indicators are inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable (e.g., as a result of excessive friction, mechanical interference, or rod control system failure), a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times once prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all Reactor Coolant Pumps (RCPs) operating and the average moderator temperature ≥ 550°F to ensure that the measured drop times will be representative of insertion times experienced during a reactor trip at operating conditions.

This Surveillance is performed during a unit outage, due to conditions needed to perform the SR and the potential for an unplanned unit transient if the Surveillance were performed with the reactor at power.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.
4. UFSAR, Section 15.4.3.
5. UFSAR, Section 15.1.5.
6. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The 53 Rod Cluster Control Assemblies (RCCAs) are divided among 4 control banks and 5 shutdown banks. A bank of RCCAs consists of either one group, or, two groups that are moved in a staggered fashion to provide for precise reactivity control but which are always within one step of each other. Each of the control banks are divided into two groups, for a total of 25 control bank rods. Shutdown banks A and B are also divided into two groups, however, shutdown banks C, D, and E have only one group each, for a total of 28 shutdown bank rods. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously (see LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements).

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either above the insertion limits specified in the COLR or fully inserted. The shutdown banks must be above the insertion limits specified in the COLR prior to withdrawing any control banks during an approach to criticality, and are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

ASES

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

    1. specified acceptable fuel design limits, or

    2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

The LCO has been modified by a Note indicating that the LCO requirement is not applicable to shutdown banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the shutdown bank to move below the LCO limits, which would normally violate the LCO. This Note applies to each shutdown bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. In MODE 3, 4, 5, or 6, the shutdown banks may be fully inserted in the core. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

ACTIONS

A.1, A.2.1, A.2.2, and A.3

If one shutdown bank is inserted less than or equal to 16 steps below the insertion limit, 24 hours is allowed to restore the shutdown bank to within the limit. This is necessary because the available SDM may be reduced with a shutdown bank not within its insertion limit. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If a shutdown bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

While the shutdown bank is outside the insertion limit, all control banks must be within their insertion limits to ensure sufficient shutdown margin is available. The 24 hour Completion Time is sufficient to repair most rod control

BASES

ACTIONS (continued)

failures that would prevent movement of a shutdown bank.

B.1.1, B.1.2, and B.2

When one or more shutdown banks is not within the insertion limits for reasons other than Condition A, 2 hours is allowed to restore the shutdown banks to within the insertion limits. Also verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the unit to remain in an unacceptable condition for an extended period of time.

C.1

If the Required Actions and associated Completion Times are not met, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are above the insertion limits specified in the COLR before the control banks are withdrawn during a unit startup.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The 53 Rod Cluster Control Assemblies (RCCAs) are divided among 4 control banks and 5 shutdown banks. A bank of RCCAs consists of either one group, or, two groups that are moved in a staggered fashion to provide for precise reactivity control but which are always within one step of each other. Each of the control banks are divided into two groups, for a total of 25 control bank rods. Shutdown banks A and B are also divided into two groups, however, shutdown banks C, D, and E have only one group each, for a total of 28 shutdown bank rods. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously (see LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements).

The control bank insertion limits are specified in a figure in the COLR. The control banks are required to be at or above the insertion limit lines.

BASES

BACKGROUND (continued)

The insertion limits figure also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. This predetermined distance is defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the shutdown and control bank insertion and alignment, AFD, and QPTR LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a Loss Of Coolant Accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

BASES

APPLICABLE SAFETY ANALYSIS

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion and alignment, AFD, and QPTR limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The control bank insertion, sequence, and overlap limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control bank insertion, sequence, and overlap, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

The LCO has been modified by a Note indicating that the LCO requirement is not applicable to control banks being inserted while performing SR 3.1.4.2. This SR verifies the freedom of the rods to move, and may require the control bank to move below the LCO limits, which would normally violate the LCO. This Note applies to each control bank as it is moved below the insertion limit to perform the SR. This Note is not applicable should a malfunction stop performance of the SR.

APPLICABILITY

The control bank insertion, sequence, and overlap limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODE 2 with $k_{eff} < 1.0$ or MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

BASES

ACTIONS

A.1, A.2.1, A.2.2, and A.3

If Control Bank A, B, or C is inserted less than or equal to 16 steps below the insertion, sequence, or overlap limits, 24 hours is allowed to restore the control bank to within the limits. Verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If a control bank is not within its insertion limit, SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

While the control bank is outside the insertion, sequence, or overlap limits, all shutdown banks must be within their insertion limits to ensure sufficient shutdown margin is available and that power distribution is controlled. The 24 hour Completion Time is sufficient to repair most rod control failures that would prevent movement of a control bank.

Condition A is limited to Control Banks A, B, or C. The allowance is not required for Control Bank D because the full power bank insertion limit can be met during performance of the SR 3.1.4.2 control rod freedom of movement (trippability) testing.

B.1.1, B.1.2, B.2, C.1.1, C.1.2, and C.2

When the control banks are outside the acceptable insertion limits for reasons other than Condition A, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

BASES

ACTIONS (continued)

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration for reasons other than Condition A, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlap limits provides an acceptable time for evaluating and repairing minor problems without allowing the unit to remain in an unacceptable condition for an extended period of time.

D.1

If the Required Actions cannot be completed within the associated Completion Times, the unit must be brought to MODE 2 with $k_{eff} < 1.0$, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The Estimated Critical Position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, GDC 28.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.

This page intentionally left blank.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control and shutdown rod position indicators to determine rod positions and thereby ensure compliance with the rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control or shutdown rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

BASES

BACKGROUND (continued)

Rod Cluster Control Assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The 53 RCCAs are divided among 4 control banks and 5 shutdown banks. A bank of RCCAs consists of either one group, or, two groups that are moved in a staggered fashion to provide for precise reactivity control but which are always within one step of each other. Each of the control banks are divided into two groups, for a total of 25 control bank rods. Shutdown banks A and B are also divided into two groups, however, shutdown banks C, D, and E have only one group each, for a total of 28 shutdown bank rods. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step 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 counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch) but not very reliable because it is a demanded position indication, not an actual position indication. For example, if a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

BASES

BACKGROUND (continued)

The DRPI System provides a highly accurate indication of actual rod position, but at a lower precision than the step counters. The DRPI System determines the actual position of each control bank and shutdown bank rod by using individual coils that are mounted concentrically along the outside boundaries of the rod drive pressure housings. Each control bank rod has 42 coil assemblies evenly spaced along its length at 3.75 inch (6 step) intervals from rod bottom to the fully withdrawn position. Each shutdown bank rod has 20 coil assemblies evenly spaced along its length at 3.75 inch intervals from rod bottom to 18 steps and from 210 steps to the fully withdrawn position, with a transition LED representing shutdown bank rod position between 18 steps and the fully withdrawn position. The coils magnetically sense the presence or absence of a rod drive shaft and send this information to two Data Cabinets located in the containment building. To prevent total loss of position indication due to a single failure, the outputs of the coils are connected alternately to Data Channel A or Data Channel B. Thus, if one data channel fails, the DRPI System can be placed in "half accuracy" mode. The DRPI System is capable of monitoring rod position within the required band of ± 12 steps in either full accuracy mode or "half accuracy mode.

Normal system accuracy is ± 4 steps (± 3 steps with an additional step added for coil placement and thermal expansion). If a data error occurs, the system is shifted to the "half accuracy" mode. As a rod is moved under "half accuracy" conditions, only every other LED will light (i.e., the LEDs associated with the operable data system) since the effective coil spacing is 7.5 inches (12 steps). Under "half accuracy" conditions with data A bad, the system accuracy is + 10 steps, - 4 steps. Under "half accuracy" conditions with data B bad, the system accuracy is + 4 steps, - 10 steps. Therefore, the normal indication accuracy of the DRPI System is ± 4 steps, and the maximum uncertainty is 10 steps. With an indicated deviation of 12 steps between the group step counter and DRPI, the maximum deviation between actual rod position and the demand position could be 22 steps.

BASES

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking, ejected rod worth, and with minimum SDM limits (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The rod position indicators monitor rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that the DRPI System for each rod and the Bank Demand Position Indication System for each group be OPERABLE. For the rod position indicators to be OPERABLE the following requirements must be met:

a. The DRPI System consisting of either Data Channel A, Data Channel B, or both data channels indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits;" and

b. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System.

BASES

LCO (continued)

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single rod, ensures high confidence that the position uncertainty of the corresponding rod group is within the assumed values used in the analysis (that specified rod group insertion limits).

These requirements ensure that rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable DRPI and each demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

BASES

ACTIONS (continued)

A.1 and A.2

When one DRPI per group in one or more groups fails, (i.e., one rod position per group can not be determined by the DRPI System) the position of the rod can still be determined by use of the movable incore detectors or Power Distribution Monitoring System (PDMS). When PDMS is OPERABLE, the position of the rod may be determined from the difference between the measured core power distribution and the core power distribution expected to exist based on the position of the rod indicated by the group step counter demand position. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

Required Action A.1 requires verification of the position of a rod with an inoperable DRPI once per 8 hours which may put excessive wear and tear on the moveable incore detector system when PDMS is inoperable; Required Action A.2 provides an alternative. Required Action A.2 requires verification of rod position every 31 EFPD, which coincides with the normal surveillance frequency for verification of core power distribution.

Required Action A.2 includes six distinct requirements for verification of the position of rods associated with an inoperable DRPI:

a. Initial verification within 8 hours of the inoperability of the DRPI;

b. Re-verification once every 31 Effective Full Power days (EFPD) thereafter;

BASES

ACTIONS (continued)

c. Verification within 8 hours if rod control system parameters indicate unintended rod movement. An unintended rod movement is defined as the release of the rod's stationary gripper when no action was demanded either manually or automatically from the rod control system, or a rod motion in a direction other than the direction demanded by the rod control system. Verifying that no unintended rod movement has occurred is performed by monitoring the rod control system stationary gripper coil current for indications of rod movement;

d. Verification within 8 hours if the rod with an inoperable DRPI is intentionally moved greater than 12 steps;

e. Verification prior to exceeding 50% RTP if power is reduced below 50% RTP; and

f. Verification within 8 hours of reaching 100% RTP if power is reduced to less than 100% RTP.

Should the rod with the inoperable DRPI be moved more than 12 steps, or if reactor power is changed, the position of the rod with the inoperable DRPI must be verified.

A.3

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position will not cause core peaking factors to approach the core peaking factor limits.

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 or A.2 above.

ACTIONS (continued)

B.1 and B.2

When more than one DRPI per group in one or more groups fail, additional actions are necessary. Placing the Rod Control System in manual assures unplanned rod motion will not occur. The immediate Completion Time for placing the Rod Control System in manual reflects the urgency with which unplanned rod motion must be prevented while in this Condition.

The inoperable DRPIs must be restored, such that a maximum of one DRPI per group is inoperable, within 24 hours. The 24 hour Completion Time provides sufficient time to troubleshoot and restore the DRPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication.

Based on operating experience, normal power operation does not require excessive rod movement. If one or more rods has been significantly moved, the Required Action of C.1 or C.2 below is required.

C.1 and C.2

With one DRPI inoperable in one or more groups and the affected groups have moved greater than 24 steps in one direction since the last determination of rod position, additional actions are needed to verify the position of rods with an inoperable DRPI. Action must be initiated immediately to verify these rods are still properly positioned, relative to their group positions.

If immediate actions have not been initiated to verify the rod's position, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps.

ACTIONS (continued)

D.1.1 and D.1.2

With one or more demand position indicator per bank inoperable in one or more banks, the rod positions can be determined by the DRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the DRPIs for the affected banks are OPERABLE and the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate. This verification can be an examination of logs, administrative controls, or other information that shows that all DRPIs in the affected bank are OPERABLE.

D.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position will not cause core peaking to approach the core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions D.1.1 and D.1.2 or reduce power to ≤ 50% RTP.

E.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the DRPI agrees with the demand position within 12 steps ensures that the DRPI is operating correctly. Since the DRPI does not display the actual shutdown rod positions between 18 and 210 steps, only points within the indicated ranges are required in comparison.

This surveillance is performed prior to reactor criticality after each removal of the reactor head, since there is potential for unnecessary plant transients if the SR were performed with the reactor at power.

The Surveillance is modified by a Note which states it is not required to be met for DRPIs associated with rods that do not meet LCO 3.1.4. If a rod is known to not to be within 12 steps of the group demand position, the ACTIONS of LCO 3.1.4 provide the appropriate Actions.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13.
2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions-MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

SECTION XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the unit. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed.

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS for reload fuel cycles in MODE 2 may include:

a. Critical Boron Concentration-Control Rods Withdrawn;

b. Critical Boron Concentration-Reference Bank Inserted;

c. Control Rod Worth; and

d. Isothermal Temperature Coefficient (ITC).

These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration-Control Rods Withdrawn Test measures the critical boron concentration at Hot Zero Power (HZP). With all rods out, the reference bank is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test could violate LCO 3.1.3, "Moderator Temperature Coefficient (MTC)."

BASES

BACKGROUND (continued)

b. The Critical Boron Concentration-Reference Bank Inserted Test measures the critical boron concentration at HZP, with a bank having the highest reactivity worth of approximately 1% $\Delta k/k$ when fully inserted into the core. This test is used to measure the differential boron worth. With the core at HZP and all banks fully withdrawn, the boron concentration of the reactor coolant is gradually lowered in a continuous manner. The reference bank is then inserted to make up for the decreasing boron concentration until the reference bank has been moved over its entire range of travel. The reactivity resulting from each incremental bank movement is measured with a reactivity computer. The difference between the measured critical boron concentration with all rods fully withdrawn and with the bank inserted is determined. The differential boron worth is determined by dividing the measured bank worth by the measured boron concentration difference. Performance of this test could violate LCO 3.1.4, "Rod Group Alignment Limits"; LCO 3.1.5, "Shutdown Bank Insertion Limits"; or LCO 3.1.6, "Control Bank Insertion Limits."

BASES

BACKGROUND (continued)

c. The Control Rod Worth Test is used to measure the reactivity worth of selected control and shutdown banks. This test is performed at HZP and has four alternative methods of performance. The first method, the Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining banks. The second method, the Rod Swap Method, measures the worth of a predetermined reference bank using the Boron Exchange Method above. The reference bank is then nearly fully inserted into the core. The selected bank is then inserted into the core as the reference bank is withdrawn. The HZP critical conditions are then determined with the selected bank fully inserted into the core. The worth of the selected bank is inferred, based on the position of the reference bank with respect to the selected bank. This sequence is repeated as necessary for the remaining banks. The third method, the Boron Endpoint Method, moves the selected bank over its entire length of travel and then varies the reactor coolant boron concentration to achieve HZP criticality again. The difference in boron concentration is the worth of the selected bank. This sequence is repeated for the remaining banks. The fourth method, the Dynamic Rod Worth Method, moves the selected bank over its entire length of travel in one continuous motion and measures its worth dynamically with a specialized reactivity computer. After the bank is subsequently withdrawn reestablishing HZP criticality, this sequence is repeated for the remaining banks. Performance of this test violates LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6.

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP and has two methods of performance. The first method, the Slope Method, varies RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The second method, the Endpoint Method, changes the RCS temperature and measures the reactivity at the beginning and end of the temperature change. The ITC is the total reactivity change divided by the total temperature change. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. The Moderator Temperature Coefficient (MTC) at Beginning Of Life (BOL) is determined from the measured ITC. This test satisfies the requirement of SR 3.1.3.1. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

APPLICABLE SAFETY ANALYSES

The fuel is protected by multiple LCOs that preserve the initial conditions of the core assumed in the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The UFSAR (Ref. 6) defines requirements for initial testing of the facility, including PHYSICS TESTS. Reference 6 summarizes the zero, low power, and power tests. Reload fuel cycle PHYSICS TESTS are outlined in ANSI/ANS-19.6.1-1985 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits of all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)," LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits," and LCO 3.4.2, "RCS Minimum Temperature for Criticality" are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 530°F, and SDM is within the limits specified in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 530 °F;

b. SDM is within the limits specified in the COLR; and

c. THERMAL POWER is maintained ≤ 5% RTP.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

<u>A.1 and A.2</u>

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the unit conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification within 1 hour.

BASES

ACTIONS (continued)

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the Reactor Trip Breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < 530°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the unit to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 530°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If Required Action C.1 cannot be completed within the associated Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ 530°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the unit is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix B, SECTION XI.
2. 10 CFR 50.59.
3. Regulatory Guide 1.68, Revision 2, August, 1978.
4. ANSI/ANS-19.6.1-1985, December 13, 1985.
5. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.
6. UFSAR Section 14.2.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density (i.e., Peak Linear Heat Rate (PLHR)) divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation when Power Distribution Monitoring System (PDMS) is inoperable, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core within power distribution limits on a continuous basis. During power operation when PDMS is OPERABLE, PLHR is measured continuously, and global power distribution continues to be limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)."

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system when PDMS is inoperable. These measurements are generally taken with the core at or near equilibrium conditions. When PDMS is OPERABLE, $F_Q(Z)$ is determined continuously.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents an equilibrium condition, it does not include the variations in the value of $F_Q(Z)$ which are present during nonequilibrium situations, such as load following or power ascension.

To account for these possible variations, the equilibrium value of $F_Q(Z)$ is adjusted as $F_Q^W(Z)$ by an elevation dependent factor that accounts for the calculated worst case transient conditions.

BASES

BACKGROUND (continued)

Core monitoring and control under non-equilibrium conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR (only when PDMS is inoperable), and control rod insertion.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a small break Loss Of Coolant Accident (LOCA) the peak cladding temperature must not exceed 2200°F and during a large break LOCA there must be a high level of probability that the peak cladding temperature does not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 Departure from Nucleate Boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the prompt energy deposition to the fuel must not exceed 200 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \le \frac{F_Q^{RTP}}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{F_Q^{RTP}}{0.5} K(Z) \qquad \text{for } P \le 0.5$$

where: F_Q^{RTP} is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

For this facility, the actual values of F_Q^{RTP} and K(Z) are given in the COLR; however, F_Q^{RTP} is normally a number on the order of 2.50, and K(Z) is a function that looks like the one provided in Figure B 3.2.1-1.

$F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

When PDMS is inoperable, an $F_Q^C(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. Then,

$$F_Q^C(Z) = F_Q^M(Z) * (1.0815)$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty.

$F_Q^C(Z)$ is an excellent approximation for $F_Q(Z)$ when the reactor is at the steady state power at which the incore flux map was taken.

BASES

LCO (continued)

When PDMS is OPERABLE, $F_Q(Z)$ is determined continuously. Then,

$$F_Q^C(Z) = F_Q^M(Z) * U_{FQ}$$

where U_{FQ} is a factor that accounts for measurement uncertainty (Ref. 4) and engineering uncertainty defined in the COLR.

The expression for $F_Q^W(Z)$ is:

$$F_Q^W(Z) = F_Q^C(Z) * W(Z)$$

where W(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR. When PDMS is inoperable, the $F_Q^C(Z)$ is calculated at equilibrium conditions.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during a small break LOCA and assures with a high level of probability that the peak cladding temperature does not exceed 2200°F during a large break LOCA (Ref. 1).

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q^C(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ may produce unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

BASES

ACTIONS

A.1, A.2, and A.3

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the unit to remain in an unacceptable condition for an extended period of time.

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 4 hours, maintains an acceptable absolute power density such that even if a transient occurred, core peaking factors are not exceeded.

ACTIONS (continued)

B.2

A reduction of the Power Range Neutron Flux-High trip setpoints by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds the limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action B.1.

B.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds the limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action B.1.

C.1

If the Required Actions of A.1 through A.3, or B.1 through B.3, are not met within their associated Completion Times, the unit must be placed in a MODE or condition in which the LCO requirements are not applicable. This is done by placing the unit in at least MODE 2 within 6 hours. The allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note (i.e., Note 1) that applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a meaningful power distribution map can be obtained. These SRs are normally performed at > 40% RTP to provide core conditions as much like the full power conditions as possible (Ref. 5). This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% RTP (and establishing equilibrium conditions) over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that $F_Q(Z)$ is verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_Q(Z)$ was last measured.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z) * (1.0815)$ (Ref. 6). $F_Q^C(Z)$ is then compared to its specified limits.

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

Typically, the top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analysis and because of the difficulty of making a precise measurement in these regions. However, the top and bottom exclusion zones can be reduced to 8% if the predicted transient peak $F_Q(Z)$ is located within the top and bottom 8% to 15% of the core. The reduction of the top and bottom exclusion zones from 15% to 8% of the core still meets the $F_Q^C(Z)$ measurement uncertainty of 5%.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance has been modified by two Notes. Note 2 requires the measured value of $F_Q^C(Z)$ be obtained from incore flux map results only when PDMS is inoperable. Note 2 modifies the required performance of the Surveillance and states that this Surveillance is not required to be performed until 12 hours after declaring PDMS inoperable, and that the last performance of SR 3.2.1.3 prior to declaring PDMS inoperable satisfies the initial performance of this SR after declaring PDMS inoperable. If SR 3.2.1.1 was not performed within its specified Frequency, this Note allows 12 hours to verify $F_Q^C(Z)$ is within limit using either the incore flux map results or by taking credit for the last performance of SR 3.2.1.3 when PDMS was OPERABLE.

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

The limit with which $F_Q^W(Z)$ is compared varies inversely with power above 50% RTP and directly with the function K(Z) provided in the COLR.

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 61 core elevations.

BASES

SURVEILLANCE REQUIREMENTS (continued)

$F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 15% inclusive; and

b. Upper core region, from 85 to 100% inclusive.

If the top and bottom exclusion zones are reduced to 8%, then $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

b. Lower core region, from 0 to 8% inclusive; and

c. Upper core region, from 92 to 100% inclusive.

Typically, the top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions. However, the top and bottom exclusion zones can be reduced to 8% if the predicted transient peak $F_Q(Z)$ is located within the top and bottom 8% to 15% of the core. The reduction of the top and bottom exclusion zones from 15% to 8% of the core still meets the $F_Q^C(Z)$ measurement uncertainty of 5%.

This Surveillance has been modified by three Notes. Note 2 may require that more frequent surveillances be performed. If $F_Q^W(Z)$ is evaluated, an evaluation of the expression below is required to account for any increase to $F_Q^M(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

If the two most recent $F_Q(Z)$ evaluations show an increase in the expression

$$\text{maximum over z} \quad \left[\frac{F_Q^C(Z)}{K(Z)} \right] ,$$

it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by the greater of the factor of 1.02 or by an appropriate factor specified in the COLR (Ref. 7), or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD.

BASES

SURVEILLANCE REQUIREMENTS (continued)

These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Note 3 requires the measured value of $F_Q^W(Z)$ be obtained from incore flux map results only when PDMS is inoperable. Note 3 modifies the required performance of the Surveillance and states that this Surveillance is not required to be performed until 12 hours after declaring PDMS inoperable, and that the last performance of SR 3.2.1.4 prior to declaring PDMS inoperable satisfies the initial performance of this SR after declaring PDMS inoperable. If SR 3.2.1.2 were not performed within its specified Frequency, this Note allows 12 hours to verify $F_Q^W(Z)$ is within limit using either the incore flux map results or by taking credit for the last performance of SR 3.2.1.4 when PDMS was OPERABLE.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

<u>SR 3.2.1.3</u>

The confirmation of the power distribution parameter, $F_Q^C(Z)$, is an additional verification over the automated monitoring performed by PDMS. This assures that PDMS is functioning properly and that the core limits are met.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note that requires the performance of SR 3.2.1.3 for determining $F_Q^C(Z)$ only when PDMS is OPERABLE.

SR 3.2.1.4

The confirmation of the power distribution parameter, $F_Q^W(Z)$, is an additional verification over the automated monitoring performed by PDMS. This assures that PDMS is functioning properly and that the core limits are met.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note that requires the performance of SR 3.2.1.4 for determining $F_Q^W(Z)$ only when PDMS is OPERABLE.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 15.4.8.
3. 10 CFR 50, Appendix A, GDC 26.
4. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.
5. ANSI/ANS-19.6.1-1985, "Reload Startup Physics Test for Pressurized Water Reactors," December 13, 1985.
6. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
7. WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control (and) F_Q Surveillance Technical Specification," February 1994.

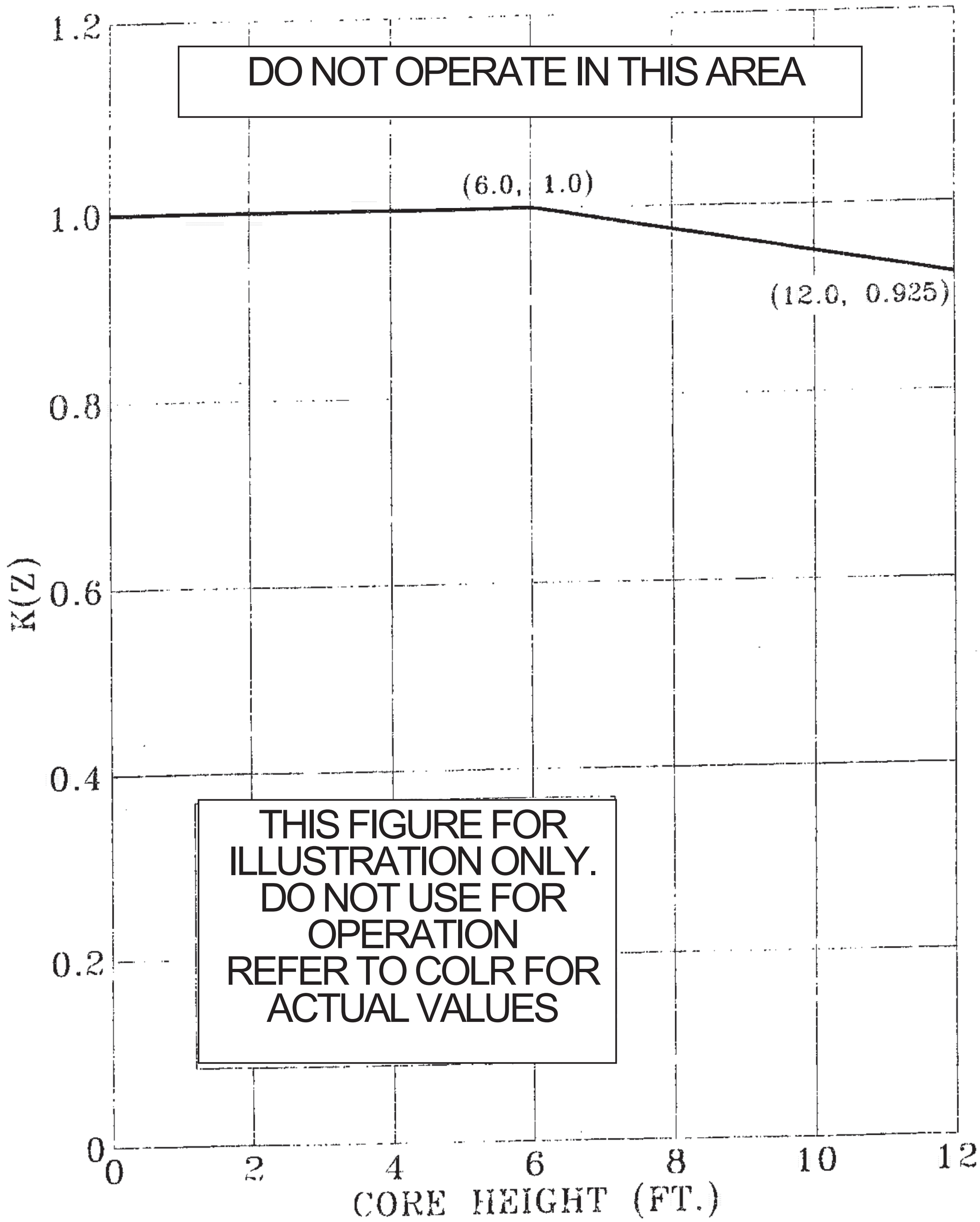

Figure B 3.2.1-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ as a function of Core Height

This page intentionally left blank.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location in the core during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, control bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

When Power Distribution Monitoring System (PDMS) is inoperable, $F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. However, during power operation when PDMS is inoperable, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables. During power operation when PDMS is OPERABLE, the linear power along the fuel rod with the highest integrated power is measured continuously and $F^N_{\Delta H}$ is determined continuously.

BACKGROUND (continued)

The COLR provides peaking factor limits that ensure that the design criterion for the Departure from Nucleate Boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

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

b. During a small break Loss Of Coolant Accident (LOCA) Peak Cladding Temperature (PCT) must not exceed 2200°F and during a large break LOCA there must be a high level of probability that PCT does not exceed 2200°F;

c. During an ejected rod accident, the prompt energy deposition to the fuel must not exceed 200 cal/gm (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required Shutdown Margin with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, $F^N_{\Delta H}$ is a significant core parameter. The limits on $F^N_{\Delta H}$ ensure that the DNB design criterion is met for normal operation, operational transients, and any transients arising from events of moderate frequency. Refer to the Bases for LCO 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits," for a discussion of the applicable Departure from Nucleate Boiling Ratio (DNBR) limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)," LCO 3.2.2, LCO 3.2.3, LCO 3.2.4, and LCO 3.2.5, "Departure from Nucleate Boiling Ratio (DNBR)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system when PDMS is inoperable. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Control Bank Insertion Limits. When PDMS is OPERABLE, $F^N_{\Delta H}$ and $F_Q(Z)$ are determined continuously. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on DNBR and Control Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the plant safety analyses.

The power multiplication factor in this equation provides margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1, A.2, A.3, and A.4

With $F^N_{\Delta H}$ exceeding its limit, Condition A is entered. $F^N_{\Delta H}$ may be restored to within its limits within 4 hours, through, for example, realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. If the value of $F^N_{\Delta H}$ is not restored to within its specified limit, THERMAL POWER must be reduced to < 50% RTP in accordance with Required Action A.1. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses.

BASES

ACTIONS (continued)

However, the DNBR limit may be violated if a DNB limiting event occurs. Reducing THERMAL POWER to < 50% RTP increases the DNB margin and is not likely to cause the DNBR limit to be violated in steady state operation. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the unit to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.4 must be completed whenever Condition A is entered. Thus, even if $F^N_{\Delta H}$ is restored within the 4 hour time period of Required Action A.1, Required Action A.2 would nevertheless require another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1. Required Action A.4 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP.

Required Action A.2 requires the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level once the power level has been reduced to < 50% RTP per Required Action A.1. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by Action A.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map when PDMS is inoperable, perform the required calculations, and evaluate $F^N_{\Delta H}$.

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, Required Action A.3 requires the Power Range Neutron Flux-High trip setpoints be reduced to ≤ 55% RTP. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin.

BASES

ACTIONS (continued)

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.3 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

Required Action A.4 requires verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence. This ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced to comply with this Required Action.

B.1

If the Required Actions of A.1 through A.4 are not met within their associated Completion Times, the unit must be placed in a MODE in which the LCO requirements are not applicable. This is done by placing the unit in at least MODE 2 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance has been modified by a Note. The Note requires the measured value of $F^N_{\Delta H}$ be obtained from incore flux map results only when PDMS is inoperable. The Note modifies the required performance of the Surveillance and states that this Surveillance is not required to be performed until 12 hours after declaring PDMS inoperable, and that the last performance of SR 3.2.2.2 prior to declaring PDMS inoperable satisfies the initial performance of this SR after declaring PDMS inoperable. If SR 3.2.2.1 were not performed within its specified Frequency, this Note allows 12 hours to verify $F^N_{\Delta H}$ is within limit using either the incore flux map results or by taking credit for the last performance of SR 3.2.2.2 when PDMS was OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.2.2

The confirmation of the power distribution parameter, $F^N_{\Delta H}$, is an additional verification over the automated monitoring performed by PDMS. This assures that PDMS is functioning properly and that the core limits are met.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note that requires the performance of SR 3.2.2.2 for determining $F^N_{\Delta H}$ only when PDMS is OPERABLE.

REFERENCES

1. UFSAR, Section 15.4.8.

2. 10 CFR 50, Appendix A, GDC 26.

3. 10 CFR 50.46.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

Relaxed Axial Offset Control (RAOC) (Ref. 2) is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the Loss of Coolant Accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

The AFD is monitored on an automatic basis using the plant process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

BASES

APPLICABLE SAFETY ANALYSES

The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The RAOC methodology establishes a xenon distribution library with tentatively wide AFD limits. Axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the LOCA. The most important Condition 3 event is the loss of flow accident. The most important Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD provide assurance that the thermal limits assumed in the accident analysis ($F^N_{\Delta H}$ and $F_Q(Z)$) are met. Thereby, the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator through the manual operation of the control banks or automatic motion of control banks. The automatic motion of the control banks is in response to temperature deviations resulting from manual operation of the Chemical and Volume Control System to change boron concentration or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 3). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detectors in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

A Note modifies the LCO by stating the AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

The AFD limits are provided in the COLR. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.

Violating this LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its specified limits.

APPLICABILITY

The AFD requirements are applicable in MODE 1 with THERMAL POWER ≥ 50% RTP (i.e., when the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis).

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

BASES

ACTIONS	<u>A.1</u> As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.2.3.1</u> This Surveillance verifies that the AFD as indicated by the NIS excore channels is within limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The AFD should be monitored and logged more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside limits.
REFERENCES	1. WCAP-8403 (nonproprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974. 2. R. W. Miller et al., "Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification," WCAP-10217(NP), June 1983. 3. UFSAR, Section 7.7.1.3.1.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses. When Power Distribution Monitoring System (PDMS) is OPERABLE, Peak Linear Heat Rate and the linear power along the fuel rod with the highest integrated power are measured continuously.

APPLICABLE SAFETY ANALYSES

Limits on QPTR preclude core power distributions that violate the following fuel design criteria:

a. During a small break Loss Of Coolant Accident (LOCA) the Peak Cladding Temperature (PCT) must not exceed 2200°F and during a large break LOCA there must be a high level of probability that the PCT does not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 Departure from Nucleate Boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the prompt energy deposition to the fuel must not exceed 200 cal/gm (Ref. 2); and

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. The control rods must be capable of shutting down the reactor with a minimum required Shutdown Margin with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion, sequence and overlap limits are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The limits on the QPTR provide assurance that the thermal limits assumed in the accident analysis ($F^N_{\Delta H}$ and $F_Q(Z)$) are met. Thereby, the QPTR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and $F^N_{\Delta H}$ is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP when PDMS is inoperable to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is neither sufficient stored energy in the fuel nor sufficient 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 below 50% RTP, but allow

BASES

APPLICABILITY (continued)

progressively higher peaking factors as THERMAL POWER decreases below 50% RTP.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% from RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

The maximum allowable power level initially determined by Required Action A.1 may be affected by subsequent determinations of QPTR. Increases in QPTR would require power reductions within 2 hours of QPTR determination, if necessary to comply with the decreased maximum allowable power level. Decreases in QPTR would allow increasing the maximum allowable power level and increasing power up to this revised limit.

A.2

After completion of Required Action A.1, periodic monitoring provides a basis for maintaining the appropriate reduced power level. As such, a check of the QPTR is required once per 12 hours. If the QPTR continues to increase, THERMAL POWER has to be reduced accordingly, such that it is maintained at a reduced power level of 3% from RTP for each 1% by which QPTR exceeds 1.00.

Any of the Surveillance methods for determining QPTR may be used within the constraints for acceptability of the Surveillance (i.e., if the excore detectors are available, they should be used; if the excore detectors are not available, the moveable incore detectors may be used). A 12 hour Completion Time is sufficient because any additional change in QPTR should be relatively slow. Further, this Completion Time is consistent with the Frequency required for the Surveillances with an inoperable alarm or instrumentation.

BASES

ACTIONS (continued)

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F^N_{\Delta H}$ and $F_Q(Z)$ within 24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 ensures that these primary indicators of power distribution are within their respective limits. Equilibrium conditions are achieved when the core is sufficiently stable at intended operating conditions to support flux mapping. The Completion Time takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the unit and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as control bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

BASES

ACTIONS (continued)

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to restore QPTR to within limit prior to increasing THERMAL POWER to above the limit of Required Action A.1. Normalization is accomplished in such a manner that the indicated QPTR following normalization is near 1.00. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by two Notes. Note 1 states that the quadrant power tilt (QPT) is not restored to within limits until after the re-evaluation of the safety analysis has determined that core conditions are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limits, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors, per Required Action A.6. These Notes are intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is restored to within limits (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours after achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

BASES

ACTIONS (continued)

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to restore QPTR to within limits (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limits and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by three Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is ≤ 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1. Note 3 modifies the required performance of the Surveillance and states that this Surveillance is not required to be performed until 12 hours after declaring PDMS inoperable. If SR 3.2.4.1 were not performed within its specified Frequency, this Note allows 12 hours to verify QPTR is within limits.

For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.4.2

With input from an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For purposes of monitoring the QPTR when input from one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map or two sets of four thimble locations with quarter core symmetry. The two sets of four symmetric thimbles is a set of eight unique detector locations.

The symmetric thimble flux map can be used to generate symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore monitoring of the radial core tilt to verify the QPTR can be used to confirm that QPTR is within limits.

With input from one NIS channel inoperable, the indicated tilt may be changed from the value indicated with input from all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This Surveillance is modified by two Notes. Note 1 states that it is not required to be performed until 12 hours after the input from one Power Range Neutron Flux channel is inoperable and the THERMAL POWER is > 75% RTP. Note 2 modifies the required performance of the Surveillance and states that this Surveillance is not required to be performed until 12 hours after declaring PDMS inoperable. If SR 3.2.4.2 were not performed within its specified Frequency, this Note allows 12 hours to verify QPTR is ≤ 1.02 using the movable incore detectors.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR, Section 15.4.8.
3. 10 CFR 50, Appendix A, GDC 26.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.5 Departure from Nucleate Boiling Ratio (DNBR)

BASES

BACKGROUND

The purpose of the limits on the value of DNBR determined by Power Distribution Monitoring System (PDMS) is to provide assurance of fuel integrity during Condition I (Normal Operation and Operational Transients) and Condition II (Faults of Moderate Frequency) events by providing the reactor operator with the information required to avoid exceeding the minimum Axial Power Shape Limiting DNBR ($DNBR_{APSL}$) in the core during normal operation and in short-term transients.

DNBR is defined as the ratio of the heat flux required to cause Departure from Nucleate Boiling (DNB) to the actual channel heat flux for given conditions.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and when PDMS is inoperable, LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core within power distribution limits on a continuous basis.

During power operation when PDMS is OPERABLE, DNBR is determined continuously. Continuously monitoring the operation of the core significantly limits the adverse nature of power distribution initial conditions for transients. The core depletion status, xenon distribution, and soluble boron concentration restrict the possible power and reactivity transients. Continuously monitoring the power distribution allows the actual DNBR value to be maintained ≥ the $DNBR_{APSL}$ value specified in the COLR. $DNBR_{APSL}$ is the DNBR value determined to be the most sensitive to the core axial power distribution at the initial conditions of the limiting accident during the cycle-specific core reload design accident analysis process.

BASES

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

> During a loss of forced reactor coolant flow accident, there must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB.

The DNB safety analysis limit for a loss of forced reactor coolant flow accident (Ref. 1) is met by limiting DNBR to the 95/95 DNB design criterion of 1.4 using the WRB-2 Critical Heat Flux (CHF) correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience DNB. Maintaining the $DNBR_{APSL}$ value ≥ the DNBR value assumed in the safety and accident analyses ensures that the 95/95 DNB design criterion of 1.4 is met.

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. When PDMS is OPERABLE, this LCO and the following LCOs ensure this: LCO 3.1.6, LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)," and LCO 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor($F^N_{\Delta H}$). When PDMS is inoperable, the following LCOs ensure this: LCO 3.1.6, LCO 3.2.1, LCO 3.2.2, and LCO 3.2.4. In addition, LCO 3.2.3 ensures that the initial conditions assumed in the safety and accident analyses remain valid regardless of PDMS operability.

DNBR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

DNBR shall be maintained within the limit of the relationship specified in the COLR.

Maintaining DNBR ≥ $DNBR_{APSL}$ ensures the core operates within the limits assumed in the safety analyses. The $DNBR_{APSL}$ limit must be maintained to prevent core power distributions from exceeding the fuel design limits for DNBR.

Another limit on DNBR is provided in SL 2.1.1, "Reactor Core SLs." LCO 3.2.5 represents the initial conditions of the safety analysis which are far more restrictive than the Safety Limit (SL). Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

BASES

APPLICABILITY

The DNBR limit must be maintained in MODE 1 with THERMAL POWER ≥ 50% RTP when PDMS is OPERABLE to ensure DNB design criteria will be met in the event of an unplanned loss of forced coolant flow transient.

ACTIONS

A.1

Parameters affecting DNBR include Reactor Coolant System (RCS) pressure, RCS average temperature, RCS total flow rate, and Thermal Power. RCS pressure and RCS average temperature are controllable and measurable parameters. RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. With DNBR not within limit due to RCS pressure or RCS average temperature, action must be taken to restore these parameter(s). With DNBR not within limit due to the indicated RCS total flow rate, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of DNBR provides sufficient time to adjust unit parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If the value of DNBR is not restored to within its specified limit, THERMAL POWER must be reduced to < 50% RTP in accordance with Required Action B.1. Reducing THERMAL POWER to < 50% RTP increases the DNB margin and is not likely to cause the DNBR limit to be violated in steady state operation. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore DNBR to within its limits without allowing the unit to remain in an unacceptable condition for an extended period of time.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.2.5.1</u> The confirmation of the power distribution parameter, DNBR, is an additional verification over the automated monitoring performed by PDMS. This assures that PDMS is functioning properly and that the core limits are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during Anticipated Operational Occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying Limiting Safety System Settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this specification as the Allowable Values, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent Departure from Nucleate Boiling (DNB);
2. Fuel centerline melt shall not occur; and
3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that dose will be within the 10 CFR 50.67 and 10 CFR 100 limits during AOOs.

BASES

BACKGROUND (continued)

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that dose shall be maintained within an acceptable fraction of 10 CFR 50.67 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RTS instrumentation is segmented into four distinct but interconnected modules as identified below. The RTS process is illustrated in UFSAR, Chapter 7 (Ref. 1):

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications;

3. Solid State Protection System (SSPS), including input, logic, and output bays: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including Reactor Trip Breakers (RTBs) and bypass breakers: provides the means to interrupt power to the Control Rod Drive Mechanisms (CRDMs) and allows the Rod Cluster Control Assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with established setpoints. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the plant computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

BASES

BACKGROUND (continued)

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1.

Two trains are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing a trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Trip Setpoints and Allowable Values

Allowable Values provide a conservative margin with regards to instrument uncertainties to ensure that SLs are not violated during AOOs and that the consequences of DBAs will be acceptable providing the unit is operated from within the LCOs at the onset of the event and required equipment functions as designed. If the measured value of a bistable exceeds the Allowable Value without tripping, then the associated RTS Function is considered inoperable. Allowable Values for RTS Functions are specified in Table 3.3.1-1.

BASES

BACKGROUND (continued)

Trip Setpoints are the nominal values at which the bistables or setpoint comparators are set. The actual nominal Trip Setpoint entered into the bistable/comparator is more conservative than that specified by the Allowable Value to account for changes in normal measurement errors detectable by a CHANNEL OPERATIONAL TEST (COT). One example of such a change in measurement error is attributable to calculated normal uncertainties during the surveillance interval. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION tolerance. If the measured value of a bistable exceeds the Trip Setpoint but is within the Allowable Value, then the associated RTS Function is considered OPERABLE. Trip Setpoints are specified in the Technical Requirements Manual (Ref. 5).

Allowable Values and Trip Setpoints are based on a methodology which incorporates all of the known uncertainties applicable for each instrument channel. References 6 and 10 provide a detailed description of the methodology used to calculate the Allowable Values and Trip Setpoints, including their explicit uncertainties, for all instruments listed in Table 3.3.1-1 except the Turbine Trip Functions. The Allowable Values and Trip Setpoints for the Turbine Trip Functions are based on specific ComEd setpoint methodology (Ref. 11).

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to initiate a reactor trip in the event of a loss of power, directing the unit to a safe shutdown condition.

BASES

BACKGROUND (continued)

The SSPS performs the decision logic for actuating a reactor trip or ESF actuation; generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the SSPS is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the SSPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal (the Reactor Trip Bypass Breaker (RTBB) shunt trip device is energized only by a manual reactor trip signal). Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

BASES

BACKGROUND (continued)

The decision logic matrix Functions are described in the functional diagrams included in Reference 1. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the decision logic matrix Functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE when the unit status is within the Applicability. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO generally requires OPERABILITY of three or four channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

   The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel activates the reactor trip breakers in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if one or more shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core or all of the rods are inserted, there is no need to be able to trip the reactor. In MODE 6, the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. <u>Power Range Neutron Flux</u>

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and the Steam Generator (SG) Water Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Power Range Neutron Flux-High

The Power Range Neutron Flux-High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux-High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux-High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux-High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. Power Range Neutron Flux-Low

The LCO requirement for the Power Range Neutron Flux-Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux-Low channels to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux-Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux-High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. Power Range Neutron Flux-High Positive Rate

The Power Range Neutron Flux-High Positive Rate trip uses the same channels as discussed for Function 2 above.

The Power Range Neutron Flux-High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and the accompanying ejection of the RCCA. This Function compliments the Power Range Neutron Flux-High and Low Setpoint trip Functions to ensure that the criteria are met for a rod ejection from the power range.

The LCO requires all four of the Power Range Neutron Flux-High Positive Rate channels to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a Rod Ejection Accident (REA), the Power Range Neutron Flux-High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux-High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux-Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux-High Setpoint trip and the Power Range Neutron Flux-High Positive Rate trip provide core protection for a rod withdrawal accident. In MODE 2 below the P-6 setpoint, the Source Range Neutron Flux Trip provides the core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

5. <u>Source Range Neutron Flux</u>

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux-Low trip Function. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal or one or more rods are not fully inserted. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical and control rod ejection events.

In MODE 2 when below the P-6 setpoint, and in MODES 3, 4, and 5 when there is a potential for an uncontrolled RCCA bank withdrawal accident, two channels of Source Range Neutron Flux trip must be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux-Low trip will provide core protection for reactivity accidents.

In MODES 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of the Function to RTS logic are not required OPERABLE. The requirements for the NIS source range detectors to monitor core neutron levels and provide indication of reactivity changes in MODE 6 are addressed in LCO 3.9.3, "Nuclear Instrumentation."

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressurizer pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has a similar effect on ΔT as a power increase. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure - the Trip Setpoint is varied to correct for changes in system pressure; and

- axial power distribution - the Overtemperature ΔT Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. A trip occurs if Overtemperature ΔT is indicated in two loops. Since the pressure and temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux-High trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and

- rate of change of reactor coolant average temperature - including dynamic compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. A trip occurs if Overpower ΔT is indicated in two loops. Since the temperature signals are used for other control functions, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

8. <u>Pressurizer Pressure</u>

The same sensors provide input to the Pressurizer Pressure-High and-Low trips and the Overtemperature ΔT trip. Since the Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. <u>Pressurizer Pressure-Low</u>

The Pressurizer Pressure-Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels of Pressurizer Pressure-Low to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, when DNB is a major concern, the Pressurizer Pressure-Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine impulse pressure P-13 greater than approximately 10% of full power equivalent). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure-High

The Pressurizer Pressure-High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires four channels of the Pressurizer Pressure-High to be OPERABLE.

The Pressurizer Pressure-High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the Power Operated Relief Valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, the Pressurizer Pressure-High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure-High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. In addition, the Low Temperature Overpressure Protection Systems provide overpressure protection in MODE 4, MODE 5, and in MODE 6 with the reactor vessel head on.

9. <u>Pressurizer Water Level-High</u>

The Pressurizer Water Level-High trip Function provides a backup signal for the Pressurizer Pressure-High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level-High to be OPERABLE. The channel Allowable Values are specified in percent instrument span. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level-High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

10. Reactor Coolant Flow-Low

The Reactor Coolant Flow-Low Function ensures that protection is provided against violating the DNBR limit due to low flow in the RCS loops, while avoiding reactor trips due to normal variations in loop flow. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow-Low channels per loop to be OPERABLE in MODE 1 above P-7. Each loop is considered a separate Function. The channel Allowable Values are specified in percent of loop minimum measured flow. The loop minimum measured flow is 96,500 gpm.

The Reactor Coolant Flow-Low Function encompasses a single loop and a two loop trip logic. In MODE 1 above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Above the P-8 setpoint, which is approximately 30% RTP, a loss of flow in any one RCS loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Reactor Coolant Pump (RCP) Breaker Position

The RCP Breaker Position trip Function operates on four auxiliary contacts per train. Each train is considered a separate Function. This Function anticipates the Reactor Coolant Flow-Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

The RCP Breaker Position trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint, a loss of flow in two or more loops will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low Trip Setpoint is reached.

One OPERABLE channel is sufficient for this Function because the RCS Flow-Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint, the RCP Breaker Position trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

12. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires four Undervoltage RCPs channels to be OPERABLE. There are two undervoltage sensing relays on each 6.9 kV bus which feeds an RCP. One relay provides an input to reactor trip logic Train A and the other relay provides an input to reactor trip logic Train B. Each reactor trip logic train requires input from two of the four buses to initiate a reactor trip. Each train is considered a separate Function.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. This Function uses the same relays as the Engineered Safety Feature Actuation System (ESFAS) Function 6.e, "Undervoltage Reactor Coolant Pump (RCP)" start of the Auxiliary Feedwater (AF) pumps.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow-Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires four Underfrequency RCPs channels to be OPERABLE. There are two underfrequency sensing relays on each 6.9 kV bus which feeds an RCP. One relay provides an input to reactor trip logic Train A and the other relay provides an input to reactor trip logic Train B. Each reactor trip logic train requires input from two of the four buses to initiate a reactor trip. Each train is considered a separate Function.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Steam Generator Water Level-Low Low

The SG Water Level-Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AF System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AF pumps on low low SG level.

The LCO requires four channels of SG Water Level-Low Low per SG to be OPERABLE in which these channels are shared between protection and control. Each SG is considered a separate Function. The Channel Allowable Values are specified in percent of narrow range instrument span.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level-Low Low trip must be OPERABLE. The normal source of water for the SGs is the Feedwater (FW) System (not safety related). The AF System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the startup feedwater pump provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level-Low Low Function does not have to be OPERABLE because the FW System may not be in operation and the reactor is not operating or critical.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

15. Turbine Trip

a. Turbine Trip-Emergency Trip Header Pressure

The Turbine Trip-Emergency Trip Header Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-8 setpoint, approximately 30% power, will not actuate a reactor trip. Two trains of three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches in either protection train will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels in each train of Turbine Trip-Emergency Trip Header Pressure to be OPERABLE in MODE 1 above P-8. Each train is considered a separate Function.

Below the P-8 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip-Emergency Trip Header Pressure trip Function does not need to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Turbine Trip-Turbine Throttle Valve Closure

The Turbine Trip-Turbine Throttle Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-8 setpoint, approximately 30% power. This action will actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the throttle valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure-High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip-Emergency Trip Header Pressure trip Function. Each turbine throttle valve is equipped with one limit switch that inputs to the RTS. Each limit switch is equipped with two contacts. One contact provides input to reactor trip logic Train A and the other contact provides an input to reactor trip logic Train B. If all four limit switches indicate that the throttle valves are all closed, a reactor trip is initiated.

The LSSS for this Function is set to assure channel trip occurs when the associated throttle valve is completely closed.

The LCO requires four Turbine Trip-Turbine Throttle Valve Closure channels per train, to be OPERABLE in MODE 1 above P-8. All four channels must trip to cause reactor trip.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Below the P-8 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip-Turbine Throttle Valve Closure trip Function does not need to be OPERABLE.

16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. This is a condition of acceptability for the Loss Of Coolant Accident (LOCA). However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Source Range Block Permissive, P-6

The Source Range Block Permissive, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range; and
- on decreasing power, the P-6 interlock enables the NIS Source Range Neutron Flux reactor trip and Boron Dilution Prevention System (BDPS) actuation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires two channels of Source Range Block Permissive, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

The intermediate range instrument scaling of 1E-11 amps to 1E-3 amps is equivalent to 1E-6% RTP to 100% RTP. The P-6 interlock setpoint allowable value of 6E-11 amps is equivalent to 6E-6% RTP.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine Impulse Pressure, P-13 interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (Two Loops);
- Reactor Coolant Pump (RCP) Breaker Position;
- Undervoltage RCPs; and
- Underfrequency RCPs.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low (Two Loops);
- RCP Breaker Position;
- Undervoltage RCPs; and
- Underfrequency RCPs.

Allowable Value are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below approximately 10% power, which is in MODE 1.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 30% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow-Low (Single Loop) reactor trip on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 30% power.

The P-8 interlock ensures that the Turbine Trip-Emergency Trip Header Pressure and Turbine Trip-Turbine Throttle Valve Closure reactor trips are enabled above the P-8 setpoint. Above the P-8 setpoint, a turbine trip may cause a load rejection beyond the capacity of the Steam Dump System. A reactor trip is automatically initiated on a turbine trip when it is above the P-8 setpoint, to minimize the transient on the reactor. On decreasing power, the reactor trips on turbine trip and low flow in one loop are automatically blocked.

The LCO requires three channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System, so the Power Range Neutron Flux interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

d. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux-Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux-Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires three channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux-Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

e. Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function provides one of the two inputs to the P-7 interlock.

The LCO requires two channels of Turbine Impulse Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine Impulse Chamber Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE trains ensures that random failure of a single logic train will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip Function exceed those specified in all related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

Consistent with the requirement in References 13 and 14 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train or an RTB train is inoperable are included. Entry into the Condition(s) is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since the Condition(s) is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition entry. If this situation were to occur during the 24-hour Completion Time of the Required Action(s) for restoration, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train or RTB train and exit the Condition(s) or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

1. To preserve Anticipated Transient Without Scram (ATWS) mitigation capability, activities that degrade the availability of the RCS pressure relief system, auxiliary feedwater (AFW) system, ATWS Mitigation System Actuation Circuitry (AMSAC), or turbine trip should not be scheduled when a logic train or RTB train is inoperable.

2. To preserve LOCA mitigation capability, one complete Emergency Core Cooling System (ECCS) train that can be actuated automatically must be maintained when a logic train is inoperable.

3. To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause RTS and ESFAS analog channels to be unavailable should not be scheduled when a logic train or RTB train is inoperable.

4. Activities that result in the inoperability of electrical systems (e.g., AC and DC power) and cooling

BASES

ACTIONS (continued)

systems (e.g., essential service water and component cooling water) that support the RCS pressure relief system, AFW system, AMSAC, turbine trip, one complete train of ECCS, and the available reactor trip and ESFAS actuation functions should not be scheduled when a logic train or RTB train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

A.1

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

ACTIONS (continued)

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods are not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, the action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

BASES

ACTIONS (continued)

A Note to the ACTIONS restricts the transition from MODE 5 with the Rod Control System not capable of rod withdrawal and all rods fully inserted, to MODE 5 with the Rod Control System capable of rod withdrawal or all rods not fully inserted for Functions 18, 19, and 20 while complying with the ACTIONS (i.e., while the LCO is not met). LCO 3.0.4 typically allows entry into MODES or other specified conditions in the Applicability while in MODE 5, however, the restriction of this Note is necessary to assure an OPERABLE RTS function prior to commencing operation with the Rod Control System capable of rod withdrawal or all rods not fully inserted.

D.1

Condition D applies to the Power Range Neutron Flux-High Function.

The NIS power range detectors provide input to the Rod Control System and the SG Water Level Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 13. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

As an alternative to the above Action, the inoperable channel can be placed in the tripped condition within 72 hours or in accordance with the Risk Informed Completion Time Program.

The Required Action is modified by a Note that allows placing one channel in bypass for 12 hours while performing surveillance testing, and setpoint adjustments when a setpoint reduction is required by other Technical Specifications.

BASES

ACTIONS (continued)

When surveillance testing is performed under the Required Action Note, the appropriate TS Condition is entered, and the Required Action Note is applied, allowing an inoperable channel to be placed in bypass for up to 12 hours. The Completion Time starts after the time in the Required Action Note expires, providing the equipment remains removed from service or bypassed. If the surveillance time exceeds 12 hours, the Required Action would have to be performed (e.g., place channel in trip within 72 hours.) In addition, if a channel is discovered inoperable, the channel may be placed in a bypass condition during troubleshooting prior to expiration of the appropriate TS Condition Required Action Completion Time to place the channel in trip. The 12 hour time limit is justified in Reference 13.

E.1

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux-Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Power Range Neutron Flux-High Positive Rate;
- Pressurizer Pressure-High; and
- SG Water Level-Low Low.

A known inoperable channel must be placed in the tripped condition within 72 hours or in accordance with the Risk Informed Completion Time Program. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 13.

BASES

ACTIONS (continued)

The Required Action is modified by a Note that allows placing one channel in bypass for 12 hours while performing surveillance testing.

When surveillance testing is performed under the Required Action Note, the appropriate TS Condition is entered, and the Required Action Note is applied, allowing an inoperable channel to be placed in bypass for up to 12 hours. The Completion Time starts after the time in the Required Action Note expires, providing the equipment remains removed from service or bypassed. If the surveillance time exceeds 12 hours, the Required Action would have to be performed (e.g., place channel in trip within 72 hours.) In addition, if a channel is discovered inoperable, the channel may be placed in a bypass condition during troubleshooting prior to expiration of the appropriate TS Condition Required Action Completion Time to place the channel in trip. The 12-hour time limit is justified in Reference 13.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 2 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The provisions of LCO 3.0.4 allow entry into a MODE or other specified condition in the Applicability as directed by the Required Actions. Therefore, a MODE change is permitted with one channel inoperable whenever Required Action F.2 is used. The NIS Intermediate Range Neutron Flux channels must be

BASES

ACTIONS (continued)

OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

H.1

Condition H applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

ACTIONS (continued)

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

I.1

Condition I applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition.

J.1 and J.2

Condition J applies to one inoperable source range channel in MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal or one or more rods not fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour, are justified in Reference 7.

BASES

ACTIONS (continued)

K.1

Condition K applies to the following reactor trip Functions:

- Pressurizer Pressure-Low;
- Pressurizer Water Level-High;
- Reactor Coolant Flow-Low;
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours or in accordance with the Risk Informed Completion Time Program. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 13.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition K.

The Required Action is modified by two Notes. The first Note applies to Functions 8a, 9, and 10 that have installed bypass capability. The Note allows placing one channel in bypass for 12 hours while performing surveillance testing. The second Note applies to Functions 12 and 13 that do not have installed bypass capability. This Note allows placing the inoperable channel in bypass for 12 hours while performing surveillance testing of other channels.

When surveillance testing is performed for functions with installed bypass test capability under the Required Action Note, the appropriate TS Condition is entered, and the Required Action Note is applied, allowing an inoperable channel to be placed in bypass for up to 12 hours. The Completion Time starts after the time in the Required Action Note expires, providing the equipment remains removed from

ACTIONS (continued)

service or bypassed. If the surveillance time exceeds 12 hours, the Required Action would have to be performed (e.g., place channel in trip within 72 hours.) In addition, for channels with installed bypass test capability, if a channel is discovered inoperable, the bypass test capability could be utilized during troubleshooting prior to expiration of the appropriate TS Condition Required Action Completion Time to place the channel in trip. The 12 hour time limit is justified in Reference 13.

L.1

If the Required Action and associated Completion Time of Condition K is not met, 6 hours is allowed to reduce THERMAL POWER to below P-7.

M.1

Condition M applies to Turbine Trip on Emergency Trip Header Pressure or on Turbine Throttle Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 72 hours or in accordance with the Risk Informed Completion Time Program. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 13.

The Required Action has been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 13.

N.1

If the Required Action and associated Completion Time of Condition M is not met, THERMAL POWER must be reduced below the P-8 setpoint within 6 hours. This places the unit in a MODE where the LCO is no longer applicable.

O.1

Condition O applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status. Alternatively, a

BASES

ACTIONS (continued)

Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The Completion Time of 24 hours (Required Action O.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable RTS Automatic Trip Logic train to OPERABLE status is justified in Reference 13.

The Required Action has been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

The 4 hour time limit for testing the RTS Automatic Trip Logic train may include testing the RTB also, if both the Logic test and the RTB test are conducted within the 4 hour time limit. The 4 hour time limit is justified in Reference 13.

<u>P.1</u>

Condition P applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The 24 hour Completion Time is justified in Reference 14.

The Required Action has been modified by a Note. The Note allows one channel to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4 hour time limit is justified in Reference 14.

<u>Q.1</u>

Condition Q applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition by observation of the associated permissive annunciator window within 1 hour. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

BASES

ACTIONS (continued)

R.1

Condition R applies to the P-7, P-8, and P-13 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition by observation of the associated permissive annunciator window within 1 hour. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions.

S.1

If the Required Action and associated Completion Time of Condition R is not met, the unit must be placed in MODE 2 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

T.1

Condition T applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or in accordance with the Risk Informed Completion Time Program.

BASES

ACTIONS (continued)

The Completion Time of 48 hours for Required Action T.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

U.1

If the Required Action and associated Completion Time of Conditions B, D, E, O, P, Q or T is not met, the unit must be placed in MODE 3 within 6 hours. The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

V.1

Condition V applies to the RCP Breaker Position reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be placed in trip within 6 hours. The 6 hour time limit is justified in Reference 11.

The Required Action has been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 4 hours while performing routine surveillance testing of the other channels. The 4-hour time limit is justified in Reference 7.

W.1

If the Required Action and associated Completion Time of Condition V is not met, THERMAL POWER must be reduced below the P-7 setpoint within 6 hours. This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-7 setpoint because other RTS Functions provide core protection below the P-7 setpoint. The 6 hours to reduce THERMAL POWER to below the P-7 setpoint is justified in Reference 14.

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that

BASES

SURVEILLANCE REQUIREMENTS (continued)

the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output prior to exceeding 75% RTP after each refueling and periodically thereafter. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is > 15% RTP.

The Frequency of once prior to exceeding 75% RTP following each refueling outage considers that the core may be changed during a refueling outage such that the previous comparison, prior to the refueling outage, is no longer completely valid. The Frequency also considers that the comparison accuracy increases with power level such that the comparison is preferred to be performed at as high a power level as possible. An initial performance at ≤ 75% RTP provides a verification prior to attaining full power.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.13. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to agree with the incore measurements. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is ≥ 75% RTP and that 24 hours is allowed for performing the first surveillance after reaching 75% RTP.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the calculated normal uncertainties consistent with the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current plant specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 7) when applicable.

SR 3.3.1.7 is modified by two Notes. Note 1 provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours, this Surveillance must be performed prior to 4 hours after entry into MODE 3.

Note 2 states that the SSPS input relays are excluded from this Surveillance for the Functions with installed bypass test capability. For the Functions with installed bypass test capability, the channel is tested in a bypassed versus a tripped condition. To preclude placing the channel in a tripped condition, the input relays are excluded from this Surveillance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by two Notes. Note 1 states that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. Note 2 states that the SSPS input relays are excluded from this Surveillance for the Functions with installed bypass test capability. For the Functions with installed bypass test capability, the channel is tested in a bypassed versus a tripped condition. To preclude placing the channel in a tripped condition, the input relays are excluded from this Surveillance.

The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within the Frequency specified in the Surveillance Frequency Control Program prior to reactor startup and four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "4 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency specified in the Surveillance Frequency Control Program thereafter applies if the unit remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the plant specific setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the calculated normal uncertainties consistent with the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP, and obtaining detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a COT of RTS interlocks. SR 3.3.1.12 is modified by a Note. The Note states that the SSPS input relays are excluded from this Surveillance for the Functions with installed bypass test capability. For the Functions with installed bypass test capability, the channel is tested in a bypassed versus a tripped condition. To preclude placing the channel in a tripped condition, the input relays are excluded from this Surveillance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. The test shall independently verify the OPERABILITY of the Undervoltage and Shunt Trip Mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of Turbine Trip Functions. This TADOT is performed prior to reactor startup. A Note states that this Surveillance is required if it has not been performed once within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the Turbine Trip Function is OPERABLE prior to taking the reactor critical. This test cannot be performed with the reactor at power and must therefore be performed prior to reactor startup.

SR 3.3.1.15

SR 3.3.1.15 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in the UFSAR, Section 7.2 (Ref. 9). Individual component response times are not modeled in the analyses.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment reaches the required functional state.

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function set to one, with the resulting measured response time compared to the appropriate UFSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing, and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. Reference 8 provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Reference 12 provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The response time may be verified for components that replace the components that were previously evaluated in Ref. 8 and Ref. 12, provided that the components have been evaluated in accordance with the NRC approved methodology as discussed in Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing,” (Ref. 15).

SR 3.3.1.15 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

BASES

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. IEEE-279-1971.
5. Technical Requirements Manual.
6. WCAP-12523, "RTS/ESFAS Setpoint Methodology Study," October 1990.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. WCAP-13632, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," August 1995.
9. UFSAR, Section 7.2.
10. WCAP-12583, "Westinghouse Setpoint Methodology For Protection Systems, Byron/Braidwood Stations," May 1990.
11. ComEd NES-EIC-20.04, Revision 0, "Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy," October 14, 1997.
12. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.
13. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
14. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2000.
15. Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing.”

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;
- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications; and
- Solid State Protection System (SSPS) including input, logic, and output bays: initiates the proper unit shutdown or Engineered Safety Feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with established setpoints. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the plant computer, and one or more control systems.

BASES

BACKGROUND (continued)

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Trip Setpoints and Allowable Values

Allowable Values provide a conservative margin with regards to instrument uncertainties to ensure that Safety Limits (SLs) are not violated during Anticipated Operational Occurrences (AOOs) and that the consequences of Design Basis Accidents (DBAs) will be acceptable providing the unit is operated from within the LCOs at the onset of the event and required equipment functions as designed. If the measured value of a bistable/contact is less conservative than the Allowable Value, then the associated ESFAS function is considered inoperable. Allowable Values for ESFAS functions are specified in Table 3.3.2-1.

BASES

BACKGROUND (continued)

Trip Setpoints are the nominal values at which the bistables or setpoint comparators are set. The actual nominal Trip Setpoint entered into the bistable/comparator is more conservative than that specified by the Allowable Value to account for changes in measurement errors detectable by a CHANNEL OPERATIONAL TEST (COT). One example of such a change in measurement error is attributable to calculated normal uncertainties during the surveillance interval. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION tolerance. If the measured value of a bistable is less conservative than the Trip Setpoint, but is within the Allowable Value, then the associated ESFAS Function is considered OPERABLE. Trip Setpoints are specified in the Technical Requirements Manual (Ref. 5).

Allowable Values and Trip Setpoints are based on a methodology which incorporates all of the known uncertainties applicable for each instrument channel. A detailed description of the methodology used to calculate the Allowable Values and Trip Setpoints, including their explicit uncertainties, is provided in References 6 and 10.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room.

BASES

BACKGROUND (continued)

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each SSPS train has a built in testing device that can automatically test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

The actuation of ESF components is accomplished through master and slave relays. The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented by the SLAVE RELAY TEST circuit, and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small Loss Of Coolant Accidents (LOCAs) and a backup actuation signal for Steam Line Breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE when the unit status is within the Applicability. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of three or four channels in each instrumentation Function and two channels in each logic and manual initiation Function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. <u>Safety Injection</u>

   Safety Injection (SI) provides two primary functions:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

   2. Boration to ensure recovery and maintenance of SDM.

   These functions are necessary to mitigate the effects of High Energy Line Breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

   - Phase A Isolation;
   - Containment Purge Isolation;
   - Reactor Trip;
   - Turbine Trip;
   - Feedwater Isolation;
   - Start of Auxiliary Feedwater (AF) pumps;
   - Control room ventilation isolation; and
   - Enabling automatic switchover of Emergency Core Cooling Systems (ECCS) pump suction to containment sump.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of FW to limit secondary side mass losses;
- Start of AF to ensure secondary side cooling capability;
- Isolation of the control room to ensure habitability; and
- Enabling ECCS suction from the Refueling Water Storage Tank (RWST) switchover on low low RWST level to ensure continued cooling via use of the containment sump.

a. <u>Safety Injection-Manual Initiation</u>

The operator can initiate SI at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO requires two channels to be OPERABLE. Each channel consists of one switch and the interconnecting wiring to the actuation logic cabinet such that either switch will actuate both trains. This ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

The applicability of the SI Manual Initiation Function is discussed with the Automatic Actuation Logic and Actuation Relay Function below.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Safety Injection-Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on an SI, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Safety Injection-Containment Pressure-High 1

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

Containment Pressure-High 1 provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High 1 must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Safety Injection-Pressurizer Pressure-Low

This signal provides protection against the following accidents:

- Inadvertent opening of a SG relief or safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Pressurizer pressure provides both control and protection functions with inputs to the Pressurizer Pressure Control System, reactor trip, and SI. Therefore, the actuation logic must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure-High 1 signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection-Steam Line Pressure-Low

Steam Line Pressure-Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure-Low provides a control input to density compensate the steam flow channels that are part of the SG water level control function. However, this control function cannot cause the events that the Function must protect against. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

With the transmitters typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function is anticipatory in nature and has a typical lead/lag ratio of 50/5.

Steam Line Pressure-Low must be OPERABLE in MODES 1, 2, and 3 (above P-11) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern. Inside containment, SLB will be terminated by automatic SI actuation via Containment Pressure-High 1, and outside containment SLB will be terminated by the Steam Line Pressure-Negative Rate-High signal for steam line isolation. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit that would result in a release of enough quantities of energy to cause a significant cooldown of the RCS.

2. Containment Spray

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

2. Reduces the amount of radioactive iodine in the containment atmosphere; and

3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;
- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure; and
- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps and mixed with a sodium hydroxide solution from the spray additive tank. When the RWST reaches the Low-3 level setpoint, the spray pump suctions are shifted to the containment sump if continued containment spray is required. Containment spray is actuated manually or automatically by Containment Pressure-High 3.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Containment Spray-Manual Initiation

The operator can initiate containment spray at any time from the control room by simultaneously turning two containment spray actuation switches in the same channel. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned simultaneously to initiate containment spray. There are two sets of two switches each in the control room. Each set of two switches is considered a channel. Simultaneously turning the two switches in either set will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two Manual Initiation channels are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation.

b. Containment Spray-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a containment spray, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. <u>Containment Spray-Containment Pressure-High 3</u>

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. Thus, the high pressure function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, since the consequences of an inadvertent actuation of containment spray could be serious. Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Four channels of containment pressure are utilized in a two-out-of-four logic configuration. Since containment pressure is not used for control, this arrangement exceeds the minimum redundancy requirements. Additional redundancy is warranted because this Function is energize to trip.

Containment Pressure-High 3 must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure-High 3 setpoint.

3. <u>Containment Isolation</u>

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. The Phase A signal isolates all automatically isolable process lines, except Component Cooling water (CC), at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the Reactor Coolant Pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CC is required to support RCP operation, not isolating CC on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CC on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Phase A Containment Isolation is actuated automatically by SI, or manually via the automatic actuation logic. All process lines penetrating containment, with the exception of CC, are isolated. CC is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and RCP motor bearing oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room. Either switch actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CC. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CC at the higher pressure does not pose a challenge to the containment boundary because the CC System is a closed loop inside containment. Although some system components do not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CC System design and Phase B isolation ensures the CC System is not a potential path for radioactive release from containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Phase B Containment Isolation is actuated by Containment Pressure-High 3, or manually, via the automatic actuation logic. For containment pressure to reach a value high enough to actuate Containment Pressure-High 3, a large break LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CC to the RCPs is, therefore, no longer necessary.

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches in either set are turned simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. <u>Containment Isolation-Phase A Isolation</u>

(1) <u>Phase A Isolation-Manual Initiation</u>

Manual Phase A Containment Isolation is actuated by either of two switches in the control room. Either switch actuates both trains. Each switch is considered a channel. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(2) <u>Phase A Isolation-Automatic Actuation Logic and Actuation Relays</u>

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. Also, there is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Isolation-Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Phase B Containment Isolation Function requires the bistable output to energize to trip in order to minimize the potential of spurious trips that may damage the RCPs.

(1) Phase B Isolation-Manual Initiation

Manual Phase B Containment Isolation is actuated by simultaneously turning two switches in the same train. There are two sets of two switches each in the control room. Each set of two switches is considered a channel.

(2) Phase B Isolation-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B containment isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) <u>Phase B Isolation-Containment Pressure-High 3</u>

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. <u>Steam Line Isolation</u>

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the MSIVs, inside or outside of containment, closure of the MSIVs and their bypass valves limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs and their bypass valves terminates the accident as soon as the steam lines depressurize.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Steam Line Isolation-Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are two switches in the control room and either switch can initiate action to immediately close all MSIVs. The LCO requires two channels to be OPERABLE.

b. Steam Line Isolation-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is not required in MODES 2 and 3 when all MSIVs and their bypass valves are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Steam Line Isolation-Containment Pressure-High 2

This Function actuates closure of the MSIVs and their bypass valves in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. The transmitters (d/p cells) and electronics are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. Containment Pressure-High 2 provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High 2 must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs and their bypass valves. The Steam Line Isolation Function is not required in MODES 2 and 3 when all MSIVs and their bypass valves are closed. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure-High 2 setpoint.

d. Steam Line Isolation-Steam Line Pressure

(1) Steam Line Pressure-Low

Steam Line Pressure-Low provides closure of the MSIVs and their bypass valves in the event of an SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. Steam Line Pressure-Low was discussed previously under SI Function 1.e.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Steam Line Pressure-Low Function must be OPERABLE in MODE 1, and in MODES 2 and 3 (above P-11), with any MSIV and associated bypass valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure-High 2. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure-Negative Rate-High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs and their bypass valves are closed. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit that would result in a release of enough quantities of energy to cause a significant cooldown of the RCS.

(2) <u>Steam Line Pressure-Negative Rate-High</u>

Steam Line Pressure-Negative Rate-High provides closure of the MSIVs and their bypass valves for an SLB when less than the P-11 setpoint, to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure-Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure-Negative Rate-High signal is automatically enabled. Steam Line Pressure-Negative Rate-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy requirements with a two-out-of-three logic on each steam line.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Steam Line Pressure-Negative Rate-High must be OPERABLE in MODE 3 when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically disabled and the Steam Line Pressure-Low signal is automatically enabled. The Steam Line Isolation Function is not required in MODE 3 when all MSIVs and their bypass valves are closed. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have an SLB or other accident that would result in a release of enough quantities of energy to cause a significant cooldown of the RCS.

While the transmitters may experience elevated ambient temperatures due to an SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

5. <u>Turbine Trip and Feedwater Isolation</u>

The primary functions of the Turbine Trip and Feedwater Isolation signals are to prevent damage to the turbine due to water in the steam lines, and to stop the excessive flow of feedwater into the SGs. These Functions are necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Function is actuated when the level in any SG exceeds the high high setpoint, and performs the following functions:

- Trips the main turbine;
- Trips the FW pumps;
- Initiates feedwater isolation; and
- Shuts the FW pump discharge valves.

This Function is actuated by SG Water Level-High High, or by an SI signal. The RTS also initiates a turbine trip signal whenever a reactor trip (P-4) is generated. In the event of SI, the unit is tripped and the turbine generator is tripped. The FW System is also taken out of operation and the AF System is automatically started.

a. Turbine Trip and Feedwater Isolation-Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Turbine Trip and Feedwater Isolation-Steam Generator Water Level-High High (P-14)

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels per SG are required to satisfy the requirements with a two-out-of-four logic. The channel Allowable Values are specified in percent of narrow range instrument span.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties.

c. Turbine Trip and Feedwater Isolation-Safety Injection

Turbine Trip and Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

Turbine Trip and Feedwater Isolation Functions must be OPERABLE in MODE 1, and in MODES 2 and 3 except when all Feedwater (FW) Isolation Valves are closed or isolated by a closed manual valve when the FW System is in operation and the turbine generator may be in operation. In MODES 4, 5, and 6, the FW System and the turbine generator are not in service and this Function is not required to be OPERABLE. The applicable FW Isolation Valves are listed below:

- FW Isolation Valve (FW009A through D)
- FW Tempering Flow Control Valve (FW034A through D)
- FW Tempering Valve (FW035A through D)
- Low Flow FW Isolation Valve (FW039A through D - Unit 1 only)
- FW Preheater Bypass Isolation Valve (FW039A through D-Unit 2 only)
- FW Isolation Bypass Valve (FW043A through D - Unit 2 only)
- FW Regulating Valve (FW510,520,530,540)
- FW Regulating Bypass Valve (FW510A,520A,530A,540A)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Auxiliary Feedwater

The AF System is designed to provide a secondary side heat sink for the reactor in the event that the FW System is not available. The system has a motor driven pump and a diesel driven pump which are described in LCO 3.7.5, "AF System."

a. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater-Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of FW, would result in a loss of SG water level. SG Water Level-Low Low provides input to the SG Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system which may then require a protection function actuation and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels per SG are required to satisfy the requirements with two-out-of-four logic. The channel Allowable Values are specified in percent of narrow range instrument span.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Auxiliary Feedwater-Safety Injection

An SI signal starts the motor driven and diesel driven AF pumps. The AF initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. Auxiliary Feedwater-Loss of Offsite Power (Undervoltage on Bus 141(241))

The loss of offsite power to bus 141(241) is detected by a voltage drop on the bus. Upon restoration of power via the "A" DG to bus 141(241), which supplies the motor driven AF pump, the motor driven AF pump will automatically start to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level-Low Low in any operating SG will cause the motor and diesel driven AF pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. These Functions do not have to be OPERABLE in MODES 4, 5, and 6 because the Steam Generators are not normally used for heat removal, and the AF System is not required.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Auxiliary Feedwater-Undervoltage Reactor Coolant Pump

A loss of power on the buses that provide power to the RCPs provides indication of a pending loss of RCP forced flow in the RCS. The Undervoltage RCP Function senses a loss of power on two or more RCP buses and starts the AF pumps to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

There are two undervoltage sensing relays on each 6.9 kV bus which feeds an RCP. One relay provides an input to actuation logic Train A and the other relay provides an input to actuation logic Train B. Each actuation logic train requires input from two of the four buses to initiate both AF pumps. Each train is considered a separate Function.

This Function must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the RCPs may be normally shut down, and thus, a pump trip is not indicative of a condition requiring automatic AF initiation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

f. Auxiliary Feedwater-Pump Suction Transfer on Suction Pressure-Low

The AF Pump Suction Pressure Channel contains a pressure switch upstream of the Pump Suction Check Valve and a pressure transmitter loop downstream of the Pump Suction Check Valve. The pressure switch upstream of the suction check valve senses Condensate Storage Tank (CST) level and will prevent a pump start if CST level cannot support pump operation. This switch will also provide an open signal to the Essential Service Water System valves to transfer the AF Pump Suction to the Safety Related Essential Service Water System. The pressure loop downstream senses pump suction pressure in all operating modes to provide pump protection and transfer to the Safety Related Essential Service Water System once the CST is depleted. The Essential Service Water System (safety grade) is then lined up to supply the AF pump to ensure an adequate supply of water for the AF System to maintain at least one of the SGs as the heat sink for reactor decay heat and sensible heat removal.

Since the detectors are located in an area not affected by HELBs or high radiation, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to ensure a safety grade supply of water for

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the AF System to maintain the SGs as the heat sink for the reactor. This Function does not have to be OPERABLE in MODES 4, 5, and 6 because the SGs are not normally used for heat removal and the AF System is not required.

7. <u>Switchover to Containment Sump</u>

At the end of the safety injection phase of a LOCA, the RWST will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is switched to the containment recirculation sump. The low head Residual Heat Removal (RHR) pumps and containment spray pumps draw the water from the containment recirculation sump, the RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the other ECCS pumps. The ECCS switchover from safety injection to cold leg recirculation is initiated automatically upon receipt of the RWST auto switchover trip signal and is completed via timely operator action at the main control board. Switchover from the RWST to the containment sump must be completed before the RWST empties to prevent damage to the ECCS pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ECCS pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. This ensures the reactor remains shut down in the recirculation mode.

Switchover is initiated via automatic opening of the containment recirculation sump isolation valves (SI8811 A/B). This automatic action aligns the suction of the RHR pumps to the containment recirculation sump to ensure continued availability of a suction source. Upon receipt of the RWST low low level switchover alarm, the operator is required to initiate the manual operations required to complete switchover in a timely manner (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Switchover to Containment Sump-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Switchover to Containment Sump-Refueling Water Storage Tank (RWST) Level-Low Low Coincident With Safety Injection

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low low level in the RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the injection phase of the LOCA. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability.

The transmitters are located in an area not affected by HELBs or post accident high radiation. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Automatic opening of the containment sump suction valves occurs only if the RWST low low level signal is coincident with SI. This prevents accidental switchover during normal operation. Accidental switchover could damage ECCS pumps if they are attempting to take suction from an empty sump. The switchover Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These Functions must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the ECCS pumps. These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually initiating the switchover and starting systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. System pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

8. Engineered Safety Feature Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Engineered Safety Feature Actuation System Interlocks-Reactor Trip, P-4

The P-4 interlock is enabled when a Reactor Trip Breaker (RTB) and its associated bypass breaker is open. Once the P-4 interlock is enabled, automatic SI initiation may be manually blocked after a 60 second time delay. This Function allows operators to take manual control of SI Systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the P-4 interlock has been momentarily cleared by closing the RTB. The functions of the P-4 interlock are:

- Trip the main turbine;
- Isolate FW coincident with low T_{avg};
- Prevent automatic reactuation of SI after a manual reset of SI; and
- Prevent opening of the FW isolation valves if they were closed on SI or SG Water Level-High High.

Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in core power. To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

None of the noted Functions serves a mitigation function in the UFSAR Chapter 15 analyses of the design basis events. Only the turbine trip Function is explicitly assumed since it is an immediate consequence of the reactor trip Function. Neither turbine trip, nor any of the other Functions associated with the reactor trip signal, is required to show that the UFSAR Chapter 15 analyses of the design basis events acceptance criteria are not exceeded.

It should be noted that the preheater bypass isolation valves (2FW039A-D) isolate on a P-4 signal during a feedline break transient (Unit 2 only). This function is required to isolate the main FW nozzle from the AF nozzle on the faulted SG, thus preventing extended blowdown from both nozzles. This functions serves a mitigation function in the UFSAR Chapter 15 analyses of the design basis events and is required to show that the UFSAR Chapter 15 analyses of the design basis events acceptance criteria are not exceeded.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize (open or close) contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a Trip Setpoint and Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, and the FW System are not in operation.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Engineered Safety Feature Actuation System Interlocks-Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal (previously discussed). When the Steam Line Pressure-Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure-Negative Rate-High is enabled. This provides protection for an SLB by closure of the MSIVs and their bypass valves.

With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure-Low and Steam Line Pressure-Low SI signals and the Steam Line Pressure-Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual reset buttons. When the Steam Line Pressure-Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure-Negative Rate-High is disabled.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Engineered Safety Feature Actuation System Interlocks-T_{avg}-Low Low, P-12

On increasing reactor coolant temperature, the P-12 interlock provides an arming signal to the Steam Dump System. On a decreasing temperature, the P-12 interlock removes the arming signal to the Steam Dump System to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump System.

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. In four loop units, these channels are used in a two-out-of-four logic.

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to have an accident.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each channel listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified on a per steam line, per loop, per SG, etc., basis, then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

BASES

ACTIONS (continued)

When the number of inoperable channels in a trip function exceeds those specified in all related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

Consistent with the requirement in References 15 and 16 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable are included. Entry into the Condition(s) is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since the Condition(s) is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition entry. If this situation were to occur during the 24-hour Completion Time of the Required Action(s) for restoration, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit the Condition(s) or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

1. To preserve Anticipated Transient Without Scram (ATWS) mitigation capability, activities that degrade the availability of the RCS pressure relief system, auxiliary feedwater (AFW) system, ATWS Mitigation System Actuation Circuitry (AMSAC), or turbine trip should not be scheduled when a logic train is inoperable.

2. To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable.

3. To preserve reactor trip and safeguards actuation capability, activities that cause master relays or slave relays in the available train to be unavailable and activities that cause RTS and ESFAS analog channels to be unavailable should not be scheduled when a logic train is inoperable, with the exception of ESFAS Function 2.c, "Containment Spray, Containment Pressure High-3," and ESFAS Function 3.b.(3), "Containment Isolation, Phase B Isolation, Containment

ACTIONS (continued)

Pressure High-3." TS 3.3.2, Condition E requires that both of these functions be placed in bypass when inoperable.

4. Activities that result in the inoperability of electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the RCS pressure relief system, AFW system, AMSAC, turbine trip, one complete train of ECCS, and the available reactor trip and ESFAS actuation functions should not be scheduled when a logic train is inoperable. That is, one complete train of a function that supports a complete train of a function noted above must be available.

A.1

Condition A applies to all ESFAS protection functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the SSPS for the functions listed above. If one channel is inoperable, 48 hours is allowed to return it to an OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. Note that for containment spray and Phase B isolation, failure of one or both switches in one channel renders the channel inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train

ACTIONS (continued)

OPERABLE for each Function, and the low probability of an event occurring during this interval.

C.1

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation;
- Phase B Isolation; and
- Automatic Switchover to Containment Sump.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 15. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval.

BASES

ACTIONS (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 4 hours is the average time required to perform channel surveillance.

D.1

Condition D applies to:

- Containment Pressure-High 1;
- Pressurizer Pressure-Low;
- Steam Line Pressure-Low;
- Containment Pressure-High 2;
- Steam Line Pressure-Negative Rate-High;
- SG Water Level-Low Low; and
- SG Water Level-High High (P-14).

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. Generally, this Condition applies to functions that operate on two-out-of-three logic or a two-out-of-four logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition is justified in Reference 15.

BASES

ACTIONS (continued)

The Required Action is modified by a Note that allows placing one channel in bypass for 12 hours while performing surveillance testing.

When surveillance testing is performed under the Required Action Note, the appropriate TS Condition is entered, and the Required Action Note is applied, allowing an inoperable channel to be placed in bypass for up to 12 hours. The Completion Time starts after the time in the Required Action Note expires, providing the equipment remains removed from service or bypassed. If the surveillance time exceeds 12 hours, the Required Action would have to be performed (e.g., place channel in trip within 72 hours or be in Mode 3 within 78 hours.) In addition, if a channel is discovered inoperable, the channel may be placed in a bypass condition during troubleshooting prior to expiration of the appropriate TS Condition Required Action Completion Time to place the channel in trip. The 12 hours allowed for testing is justified in Reference 15.

E.1

Condition E applies to:

- Containment Spray Containment Pressure-High 3; and
- Containment Phase B Isolation Containment Pressure-High 3.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion.

BASES

ACTIONS (continued)

Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed in a trip condition). The Completion Time is further justified based on the low probability of an event occurring during this interval.

The Required Action is modified by a Note that allows one additional channel to be bypassed for up to 12 hours for surveillance testing. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on the results of Reference 15.

BASES

ACTIONS (continued)

F.1

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval.

G.1

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation, Turbine Trip and Feedwater Isolation, and AF actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The 24 hours allowed to restore the inoperable train to OPERABLE status is justified in Reference 15. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval.

The Required Action is modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

BASES

ACTIONS (continued)

H.1

Condition H applies to Loss of Offsite Power. For this Function, if one channel is inoperable, 1 hour is allowed to restore the channel to OPERABLE status or to place it in the tripped condition.

The Required Action is modified by a Note that allows the inoperable channel to be bypassed for up to 2 hours for surveillance testing of other channels. The 1 hour allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 2 hours allowed for testing, are deemed acceptable based on engineering judgement.

BASES

ACTIONS (continued)

I.1

Condition I applies to the Undervoltage Reactor Coolant Pump Function.

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If placed in the tripped condition, the Function is then in a partial trip condition on the affected train where one-out-of-three logic will result in actuation.

The Required Action is modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 15.

J.1

Condition J applies to the Auxiliary Feedwater Pump Suction Transfer on Suction Pressure-Low Function. With one train inoperable, the associated auxiliary feedwater pump must be immediately declared inoperable. This requires entry into applicable Conditions and Required Actions of LCO 3.7.5, "AF System."

BASES

ACTIONS (continued)

K.1

Condition K applies to the RWST Level-Low Low Coincident with Safety Injection Function.

If one channel is inoperable, the inoperable channel must be placed in the tripped condition within 72 hours or in accordance with the Risk Informed Completion Time Program.

RWST Level-Low Low Coincident with SI provides actuation of switchover to the containment sump. Note that this Function requires the bistables to energize to perform their required action.

This Condition applies to a Function that operates on two-out-of-four logic. Therefore, failure of one channel places the Function in a two-out-of-three configuration. One channel must be tripped to place the Function in a one-out-of-three configuration that satisfies redundancy requirements.

The Required Action is modified by a Note that allows placing one channel in bypass for 12 hours while performing surveillance testing.

When surveillance testing is performed under the Required Action Note, the appropriate TS Condition is entered, and the Required Action Note is applied, allowing an inoperable channel to be placed in bypass for up to 12 hours. The Completion Time starts after the time in the Required Action Note expires, providing the equipment remains removed from service or bypassed. If the surveillance time exceeds 12 hours, the Required Action would have to be performed (e.g., place channel in trip within 72 hours or be in Mode 3 within 78 hours.) In addition, if a channel is discovered inoperable, the channel may be placed in a bypass condition during troubleshooting prior to expiration of the appropriate TS Condition Required Action Completion Time to place the channel in trip. This is acceptable based on the results of Reference 15.

BASES

ACTIONS (continued)

L.1

Condition L applies to the P-11 and P-12 interlocks.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour.

M.1 and M.2

If the Required Action and associated Completion Time of Conditions B, C, or K is not met, the unit must be placed in a MODE in which LCO does not apply. This is accomplished by placing the unit in MODE 3 within 6 hours and MODE 5 within 36 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. In MODE 5, these Functions are no longer required OPERABLE.

N.1 and N.2

If the Required Action and associated Completion Time of Conditions D, E, F, G, H, or L is not met, the unit must be placed in MODE 3 within 6 hours and MODE 4 within 12 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. In MODE 4, these Functions are no longer required OPERABLE.

O.1

If the Required Action and associated Completion Time of Condition I is not met, the unit must be placed in MODE 3 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, these Functions are no longer required OPERABLE.

BASES

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.2.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.2

SR 3.3.2.2 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the calculated normal uncertainty consistent with the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current plant specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 7) when applicable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a TADOT. This test is a check of the Loss of Offsite Power Function. The Function is tested up to, and including, the master relay coils.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.4

SR 3.3.2.4 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. The time allowed for the testing (4 hours) is justified in Reference 7. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a COT. SR 3.3.2.6 is modified by a Note. The Note states that the SSPS input relays are excluded from this Surveillance for the Functions with installed bypass test capability. For the Functions with installed bypass test capability, the channel is tested in a bypassed versus a tripped condition. To preclude placing the channel in a tripped condition, the input relays are excluded from this Surveillance.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the calculated normal uncertainty consistent with the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current plant specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 16.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT. This test is a check of the Undervoltage RCP Function. The Function is tested up to, and including, the master relay coils.

The test also includes trip devices that provide actuation signals directly to the SSPS. The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.9

SR 3.3.2.9 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and P-4 Reactor Trip Interlock. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions have no associated setpoints.

SR 3.3.2.10

SR 3.3.2.10 is the performance of a CHANNEL CALIBRATION.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the plant specific setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.11 and SR 3.3.2.12

These SRs ensure the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing acceptance criteria are included in the UFSAR, Section 7.3, (Ref. 9). Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the Trip Setpoint value at the sensor, to the point at which the equipment reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate UFSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing, and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) inplace, onsite, or offsite (e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. Reference 8 provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Reference 11 provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

The response time may be verified for components that replace the components that were previously evaluated in Ref. 8 and Ref. 11, provided that the components have been evaluated in accordance with the NRC approved methodology as discussed in Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing,” (Ref. 17).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 7.

3. UFSAR, Chapter 15.

4. IEEE-279-1971.

5. Technical Requirements Manual.

6. WCAP-12523, "RTS/ESFAS Setpoint Methodology Study," October 1990.

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. WCAP-13632 Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," August 1995.

9. UFSAR, Section 7.3.

10. WCAP-12583, "Westinghouse Setpoint Methodology For Protection Systems, Byron/Braidwood Stations," May 1990.

11. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.

12. WCAP-13877, Revision 2-P, "Reliability Assessment of Westinghouse Type AR Relays Used as SSPS Slave Relays," October 1999.

13. WCAP-13878-P, Revision 2, "Reliability Assessment of Potter & Brumfield MDR Series Relays," October 1999.

14. WCAP-13900, Revision 0, "Extension of Slave Relay Surveillance Test Intervals," April 1994.

15. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

16. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2000.

17. Attachment 1 to TSTF-569, “Methodology to Eliminate Pressure Sensor and Protection Channel (for Westinghouse Plants only) Response Time Testing”

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by plant specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during plant specific implementation of Regulatory Guide 1.97 as Type A and Category I variables.

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

BASES

BACKGROUND (continued)

Category I variables 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 for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the plant specific Regulatory Guide 1.97 analyses (Ref. 1) and are consistent with the current plant licensing basis. These analyses identify the plant specific Type A and Category I variables and provide justification for deviating from the requirements of Regulatory Guide 1.97.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

BASES

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., Loss Of Coolant Accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;
- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Selected Category I, non-Type A, instrumentation are included in Technical Specifications because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk and satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A instruments, which provide information required by the control room operators to perform certain manual actions specified in the Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses selected Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. More than two channels may be required if it is determined that failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function.

Table 3.3.3-1 lists all Type A and Category I variables identified by the plant specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER (Ref. 1) with the exception of the containment spray add tank level.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

BASES

LCO (continued)

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Reactor Coolant System (RCS) Pressure (Wide Range)

RCS wide range pressure is a Category I variable provided for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify delivery of Safety Injection (SI) flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure is also used to verify closure of manually closed spray line valves and pressurizer Power Operated Relief Valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS pressure can also be used:

- To determine whether to terminate actuated SI or to reinitiate stopped SI;
- To determine when to reset SI and shut off Emergency Core Cooling System (ECCS) pumps;
- To manually restart ECCS pumps;
- As Reactor Coolant Pump (RCP) trip criteria; and
- To make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

BASES

LCO (continued)

RCS pressure is also related to three decisions about depressurization. They are:

- To determine whether to proceed with primary system depressurization;
- To verify termination of depressurization; and
- To determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a Steam Generator Tube Rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting Steam Generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

2, 3. <u>RCS Hot and Cold Leg Temperatures (Wide Range)</u>

RCS Hot and Cold Leg Temperatures are Category I variables provided for verification of core cooling and long term surveillance.

RCS Hot and Cold Leg Temperatures may be used as a backup to determine RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

In addition, RCS Cold Leg Temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS.

BASES

LCO (continued)

4. Steam Generator Water Level (Wide Range)

Wide Range SG water level is a Type A variable used to determine if an adequate heat sink is being maintained through the SGs for decay heat removal, primarily for the response to a loss of secondary heat sink event when the level is below the narrow range. The wide range SG level indication may also be used in conjunction with auxiliary feedwater flow for SI termination. In addition, the wide range level is cold calibrated and provides a complete range for monitoring SG level during a cooldown. Auxiliary feedwater flow provides a diverse indication for wide range SG water level. Four channels (one on each SG) are required to be OPERABLE.

5. Steam Generator Water Level (Narrow Range)

Narrow Range SG water level is a Type A variable used to determine if an adequate heat sink is being maintained through the SGs for decay heat removal and to maintain the SG level and prevent overfill. It is also used to determine whether SI should be terminated and may be used to diagnose an SG tube rupture event. Four channels (one on each SG) are required to be OPERABLE.

6. Pressurizer Water Level

Pressurizer Water Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

BASES

LCO (continued)

7. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to verify closure of Main Steam Isolation Valves (MSIVs), and containment spray Phase B isolation when High-3 containment pressure is reached.

8. Steam Line Pressure

Steam Line Pressure is a Type A variable provided for the following:

- Determining if a high energy secondary line break occurred and which steam generator is faulted;
- Maintaining an adequate heat sink;
- Verifying Auxiliary Feedwater flow to the faulted steam generator is isolated;
- Verifying operation of pressure control steam dump system;
- Maintaining the unit in a cold shutdown condition;
- Monitoring the RCS cooldown rate; and
- Providing diverse indication to Cold Leg temperature for natural circulation determination.

Two channels per steam line are required with sufficient accuracy to determine the faulted steam generator.

BASES

LCO (continued)

9. Refueling Water Storage Tank (RWST) Level

The RWST Level is a Type A variable provided for verifying a water source to the ECCS and Containment Spray, determining the time for initiation of cold leg recirculation following a LOCA and event diagnosis.

The RWST level accuracy is established to allow an adequate supply of water to the Residual Heat Removal and Containment Spray pumps during the switchover to cold leg recirculation mode. A high degree of accuracy is required to maximize the time available to the operator to complete the switchover to the cold leg recirculation phase and ensure sufficient water is available to avoid losing pump suction.

10. Containment Floor Water Level (Wide Range)

Containment Floor Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Floor Water Level is used to determine:

- Containment water level accident diagnosis;
- When cold leg recirculation can be implemented; and
- Whether to terminate SI, if still in progress.

11. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine if a High Energy Line Break has occurred, and whether the event is inside or outside of containment.

BASES

LCO (continued)

12. Main Steam Line Radiation

The Main Steam Line Radiation level is a Type A variable provided to allow detection of gross secondary side radioactivity and to provide a means to identify the ruptured steam generator. Steam generator narrow range level serves as diverse indication for the one monitor per loop required.

13. Core Exit Temperature

Core Exit Thermocouples are used as a primary means to determine RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid Core Exit Thermocouples (CETCs) necessary for measuring core cooling. The evaluation determined the reduced complement of CETCs necessary to detect initial core recovery and trend the ensuing core heatup. The evaluations account for core nonuniformities, including incore effects of the radial decay power distribution, excore effects of condensate runback in the hot legs, and nonuniform inlet temperatures. Adequate core cooling is ensured with four CETCs per quadrant. Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

BASES

LCO (continued)

14. Reactor Vessel Water Level

Reactor Vessel Water Level is provided for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the liquid level above the fuel. Two channels are required OPERABLE (Train A and Train B). Each channel consists of eight sensors on a probe. For a channel to be considered OPERABLE one of the two sensors in the "head" region and three of the six sensors in the "plenum" region shall be OPERABLE. The level indicated by the OPERABLE sensors represents the amount of liquid mass that is in the reactor vessel above the core. Operability of each sensor may be determined by reviewing the error codes displayed on the control room indicator.

15. (Deleted)

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

BASES

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to all PAM Functions. Condition A addresses the situation where one or more Functions with one or more required channels are inoperable. The Required Action is to refer to Table 3.3.3-1 and to take the Required Actions for the Functions affected. The Completion Times are those from the reference Conditions and Required Actions.

B.1

If Condition B is required to be entered by Table 3.3.3-1, the inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel, the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

BASES

ACTIONS (continued)

C.1

Condition C applies when the Required Action and associated Completion Time for Condition B are not met. This Required Action specifies the immediate initiation of actions in accordance with Specification 5.6.7, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

D.1 and E.1

Condition D applies to Functions with one required channel as required to be entered by Table 3.3.3-1. Required Action D.1 requires restoration of an inoperable channel within 7 days. Condition E applies to one or more Functions with two or more required inoperable channels on the same Function. Required Action E.1 requires all but one channel on the same Function be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with no required channels OPERABLE in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of the channel(s) limits the risk that the PAM Function will be in a degraded condition should an accident occur.

BASES

ACTIONS (continued)

F.1 and F.2

If the Required Action and associated Completion Time of Condition D or E is not met, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours. Condition F is also modified by a Note that excludes Functions 11, 12, and 14.

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 plant systems.

G.1

If the Required Action and associated Completion Time of Condition D or E is not met, Required Action G.1 specifies the immediate initiation of actions in accordance with Specification 5.6.7. This Specification requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the low likelihood of unit conditions that would require information provided by this instrumentation. Condition G is modified by a Note that indicates that this Condition is only applicable to Functions 11, 12, and 14.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar instruments located throughout the plant.

Agreement criteria are determined based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. The CHANNEL CALIBRATION may consist of an electronic calibration of the channel for range decades above 10 R/h and a one point calibration check of the detector below 10 R/h with an installed or portable gamma source.

This SR is modified by a Note that excludes the radiation detector for Function 11, Containment Area Radiation. For this Function, the CHANNEL CALIBRATION may consist of an electronic calibration of the remainder of the channel for range decades above 10 R/hr, and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the CETC sensors, which may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel, is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. Safety Evaluation Report, dated May 19, 1989.
2. Regulatory Guide 1.97, Revision 3, May 1983.
3. NUREG-0737, Supplement 1, "TMI Action Items."

This page intentionally left blank.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND	The Remote Shutdown System provides the control room operator with sufficient instrumentation that supports placing and maintaining the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AF) System and the main steam safety valves or the Steam Generator (SG) Power Operated Relief Valves (PORVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AF System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3. If the control room becomes inaccessible, the operators can monitor the status for placing and maintaining the unit in MODE 3. The unit can be maintained safely in MODE 3 for an extended period of time. The OPERABILITY of the remote shutdown instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.
APPLICABLE SAFETY ANALYSES	The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3. The criteria governing the design and specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1). The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it has been retained in the Technical Specifications as satisfying Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the monitoring instrumentation necessary to place and maintain the unit in MODE 3 from a location other than the control room. The required instrumentation is listed in Table 3.3.4-1 in the accompanying LCO.

The monitoring instrumentation is required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AF System and the main steam safety valves or SG PORVs; and
- RCS inventory control via charging flow.

A Function of a Remote Shutdown System is OPERABLE if all instrument channels needed to support the Remote Shutdown System Function are OPERABLE. In some cases, Table 3.3.4-1 may indicate that the required information is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information sources is OPERABLE.

The remote shutdown monitoring instrument circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the monitoring instruments will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument functions if control room instruments become unavailable.

BASES

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System listed in Table 3.3.4-1 are inoperable.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

B 3.3 INSTRUMENTATION

B 3.3.5 Loss Of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage, degraded voltage or low degraded voltage condition occurs. There are two LOP start signals, one for each 4.16 kV ESF bus.

Two undervoltage relays with inverse time characteristics are provided on each 4.16 kV ESF bus for detecting a loss of bus voltage condition; two degraded voltage relays with definite time characteristics are provided on each 4.16 kV ESF bus for detecting a sustained degraded voltage condition; and two low degraded voltage relays with definite time characteristics are provided on each 4.16 kV ESF bus for detecting a low degraded voltage condition.

The undervoltage relays are combined in a two-out-of-two logic to generate an LOP signal if the voltage is below a nominal setpoint of 70% for a short time delay for the first-level undervoltage condition (i.e., loss of voltage condition). The two degraded voltage relays are also combined in a two-out-of-two logic to generate an LOP signal if the voltage is below a nominal setpoint of 92.5% for a long time for the second-level undervoltage condition (i.e., degraded voltage condition). Similarly, the two low degraded voltage relays are combined in a two-out-of-two logic to generate an LOP signal if the voltage is below a nominal setpoint of 75% for a short time for the third-level undervoltage condition (i.e., low degraded voltage condition). The LOP start actuation is described in UFSAR, Section 8.3 (Ref. 1).

<u>Trip Setpoints and Allowable Values</u>

Allowable Values provide a conservative margin with regards to instrument uncertainties to ensure analytical limits are not violated during anticipated operational occurrences and that the consequences of Design Basis Accidents (DBAs) will be acceptable providing the unit is operated from within the LCOs at the onset of the event and required equipment functions as designed.

BASES

BACKGROUND (continued)

Trip Setpoints are the nominal values at which the relays are set. The actual nominal Trip Setpoint entered into the relay is more conservative than that specified by the Allowable Value to account for changes in random and non-random measurement errors. One example of such a change in measurement error is attributable to calculated normal uncertainties during the surveillance interval. Any relay is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION tolerance. If the measured value of a relay exceeds the Trip Setpoint but is within the Allowable Value, then the associated LOP DG Start Instrumentation function is considered OPERABLE. Trip Setpoints are specified in Reference 2.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the Engineered Safety Feature Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a Loss Of Coolant Accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 3, in which a loss of offsite power is assumed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG start instrumentation requires that two channels (i.e., two relays) per bus of the loss of voltage, degraded voltage and low degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the channels must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power, DG A powers the motor driven auxiliary feedwater pump. Failure of this pump to start would leave only the diesel driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

BASES

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered separately for each Function listed in the LCO on a per bus basis. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

<u>A.1</u>

Condition A applies to the LOP DG Start Instrumentation Function with one channel on one or more buses inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 1 hour or in accordance with the Risk Informed Completion Time Program. With a channel in trip, the LOP DG Start Instrumentation channels are configured to provide a one-out-of-one logic to initiate an undervoltage, degraded voltage signal or low degraded voltage for that bus.

For the Loss of Voltage Function, a Note is added to allow bypassing an inoperable channel for up to 2 hours for surveillance testing of the other channel. This allowance is made where bypassing the channel does not cause an actuation.

The specified Completion Time is reasonable considering the low probability of an event occurring during these intervals.

<u>B.1</u>

Condition B applies to each of the LOP DG Start Instrumentation Functions with two channels on one or more buses inoperable.

Required Action B.1 requires restoring one channel of the affected Function to OPERABLE status. The 1 hour Completion Time takes into account the low probability of an event requiring an LOP start occurring during this interval. Alternatively, a Completion Time can be determined in

BASES

ACTIONS (continued)

accordance with the Risk Informed Completion Time Program.

A Note has been added in the COMPLETION TIME for Required Action B.1 to clarify the application for entry of the Risk Informed Completion Time (RICT) Program. Although the Conditions of this Specification may be entered separately for each Function listed in the LCO on a per bus basis, RICT entry is not permitted for the Loss of Function Condition when the same Function is inoperable on more than one bus.

C.1

Condition C applies to each of the LOP DG Start Instrumentation Functions when the Required Action and associated Completion Time for Condition A or B are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources-Operating," or LCO 3.8.2, "AC Sources-Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure plant safety.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of relay setpoints during the TADOT

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage, a degraded voltage and a low degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as described in Reference 1.

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 8.3.
2. Technical Requirements Manual.
3. UFSAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Ventilation Isolation Instrumentation

BASES

BACKGROUND

Containment ventilation isolation instrumentation closes the containment isolation valves in the Minipurge System and the Normal Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. A discussion of the containment ventilation system is provided in the Bases for LCO 3.6.3, "Containment Isolation Valves."

Containment ventilation isolation initiates on an automatic Safety Injection (SI) signal, by manual actuation of Phase A Isolation, by manual actuation of Phase B Isolation, or by a high radiation signal from RE-AR011 or RE-AR012. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss the ESFAS modes of initiation.

Two radiation monitoring channels (RE-AR011 and RE-AR012) provide input to the containment ventilation isolation. Each of the purge systems has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from RE-AR011 initiates Train A containment ventilation isolation, which closes the inner containment isolation valves. A high radiation signal from RE-AR012 initiates Train B containment purge isolation, which closes the outer containment isolation valves.

The trip setpoint is established such that the actual dose rate would not exceed two times background at Rated Thermal Power (RTP) in the containment building.

BASES

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event (i.e., within approximately 60 seconds). The isolation of the purge valves has not been analyzed mechanistically in the dose calculations, although its rapid isolation is assumed. The containment ventilation isolation radiation monitors act as backup to the SI signal to ensure closing of the purge valves. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental radiological doses are below 10 CFR 50.67, "Accident Source Term," (Ref. 1) limits.

The containment ventilation isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation - Phase A

   Refer to LCO 3.3.2, Function 3.a.1, for all initiating Functions and requirements.

2. Manual Initiation - Phase B

   Refer to LCO 3.3.2, Function 3.b.1, for all initiating Functions and requirements.

BASES

LCO (continued)

3. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for Engineered Safety Feature Actuation System (ESFAS) Function 1.b, SI, ESFAS Function 3.a, Containment Phase A Isolation, and ESFAS Function 3.b, Containment Phase B Isolation. If one or more of the SI, Phase A isolation, or Phase B isolation Functions becomes inoperable in such a manner that only the Containment Ventilation Isolation Function is affected, the Conditions applicable to their ESFAS SI, Phase A isolation, and Phase B isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Ventilation Isolation Function specify sufficient compensatory measures for this case.

4. Containment Radiation

The LCO specifies two required channels to ensure that the radiation monitoring instrumentation necessary to initiate Containment Ventilation Isolation remains OPERABLE. The radiation monitoring channel is OPERABLE when it is capable of providing a containment ventilation isolation signal up to the final actuation device(s) (i.e., required containment purge valves).

5. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

BASES

APPLICABILITY

The Containment Ventilation Isolation Functions must be OPERABLE in the MODES identified in Table 3.3.6-1. Under these conditions, the potential exists for an accident that could release fission product radioactivity into containment. Therefore, the containment ventilation isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without fuel handling in progress or when moving fuel in containment that is not RECENTLY IRRADIATED FUEL, the containment ventilation isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1. If fuel handling is in progress for RECENTLY IRRADIATED FUEL, the containment ventilation isolation instrumentation need not be OPERABLE as each penetration providing access from the containment atmosphere to the outside atmosphere must be closed by a manual or automatic isolation valve, blind flange, or equivalent in accordance with LCO 3.9.4.c.

The Applicability for the containment ventilation isolation on the ESFAS Manual Initiation-Phase A, Manual Initiation-Phase B, and Safety Injection Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the Manual Initiation-Phase A, Manual Initiation-Phase B, and Safety Injection Functions Applicabilities. The Applicability for the containment ventilation isolation Automatic Actuation Logic and Actuation Relays is MODES 1, 2, 3, and 4. The Applicability for the containment ventilation isolation on Containment Radiation - High is MODES 1, 2, 3, 4.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

BASES

ACTIONS (continued)

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for the Automatic Actuation Logic and Actuation Relays Function and the Containment Radiation - High Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of the given Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of one containment ventilation isolation radiation monitor channel. Condition A requires the inoperable channel to be restored to OPERABLE status within 4 hours. The Completion Time is justified by the low likelihood of events occurring during this interval, and recognition that the remaining channel will respond to most events.

B.1

Condition B addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for the Containment Ventilation Isolation Function. It also addresses the failure of both radiation monitoring channels or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If one or both automatic actuation trains are inoperable, both radiation monitoring channels are inoperable, or the Required Action and associated Completion Time of Condition A is not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Ventilation Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR has been modified by a Note stating that the Surveillance is only applicable to the actuation logic of the ESFAS Instrumentation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR has been modified by a Note stating that the Surveillance is only applicable to the master relays of the ESFAS Instrumentation.

SR 3.3.6.4

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This test verifies the capability of the instrumentation to provide the containment ventilation system isolation. The setpoint shall be left consistent with the current plant specific calibration procedure tolerance.

SR 3.3.6.5

SR 3.3.6.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.6

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67.
2. NUREG-1366, December 1992.
3. WCAP-13877, Revision 2-P, "Reliability Assessment of Westinghouse Type AR Relays Used as SSPS Slave Relays," October 1999.
4. WCAP-13878-P, Revision 2, "Reliability Assessment of Potter & Brumfield MDR Series Relays," October 1999.
5. WCAP-13900, Revision 0, "Extension of Slave Relay Surveillance Test Intervals," April 1994.
6. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2000.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation (VC) Filtration System Actuation Instrumentation

BASES

BACKGROUND

The VC Filtration System provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the VC Filtration System provides control room ventilation. Upon receipt of an actuation signal, the VC Filtration System initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Ventilation (VC) Filtration System."

The actuation instrumentation consists of two high radiation channels in each of the outside air intakes. A high radiation (gaseous) signal from one of two channels will initiate its associated train of the VC Filtration System and trip the Control Room Offices HVAC (VV) System. The VC Filtration System is also actuated by a Safety Injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

The radiological dose assessments performed for the applicable Design Basis Accidents (DBAs) assume initiation of the VC Filtration System within 30 minutes.

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The VC Filtration System acts to terminate the supply of unfiltered outside air to the control room, initiate filtration, and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, the radiation monitor actuation of the VC Filtration System provides a protected environment from which operators can control the unit following a DBA.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The radiation monitor actuation of the VC Filtration System in MODES 5 and 6, and during movement of irradiated fuel assemblies is the primary means to ensure control room habitability in the event of a fuel handling or other event which could provide a significant radioactive release.

The VC Filtration System actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirements ensure that the control room air intake radiation-gaseous instrumentation necessary to initiate the VC Filtration System is OPERABLE. The LCO specifies two channels per train (ORE-PR031B and ORE-PR032B for Train A and ORE-PR033B and ORE-PR034B for Train B.

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements for the SI instrumentation which actuates the VC Filtration System.

APPLICABILITY

The VC Filtration System Functions must be OPERABLE in MODES 1, 2, 3, 4, and at all times during movement of irradiated fuel assemblies. The Functions must be OPERABLE in MODES 5 and 6 to provide protection from significant radioactivity releases.

The Applicability for the VC Filtration System actuation on the Engineered Safety Feature Actuation System (ESFAS) SI Functions are specified in LCO 3.3.2. Refer to the Bases for LCO 3.3.2 for discussion of the SI Function Applicability.

BASES

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A.1 and A.2

Condition A applies to the failure of one or more radiation channels in one VC Filtration System train. If one or more channels on one train is inoperable, one hour is permitted to either place the redundant VC Filtration System train in the normal mode of operation or to place one VC Filtration System train in the emergency mode of operation. The Completion Time of one hour is sufficient to ensure that the train operating in the normal mode is the train opposite from the train associated with the inoperable channel. An alternate action would be to place either train in the emergency mode. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

B.1

Condition B applies to the failure of one or more radiation channels in both VC Filtration System trains. If one or more channels on both trains are inoperable, one VC Filtration System train must be placed in the emergency mode of operation within 1 hour. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time of Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the likelihood of an event requiring the VC Filtration System is minimized. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 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 plant systems.

D.1

Condition D applies when the Required Action and associated Completion Time of Condition A or B have not been met when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require VC Filtration System actuation.

E.1

Condition E applies when the Required Action and associated Completion Time of Condition A or B have not been met in MODE 5 or 6. Actions must be initiated immediately to restore the inoperable train(s) to OPERABLE status to provide protection from significant radioactivity releases.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which VC Filtration System Actuation Function.

SR 3.3.7.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.2

A COT is performed on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the VC Filtration System actuation. The setpoints shall be left consistent with the plant specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.3

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.8 Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System Actuation Instrumentation

BASES

BACKGROUND

The FHB Ventilation System ensures that radioactive materials in the fuel handling building atmosphere following a fuel handling accident involving RECENTLY IRRADIATED FUEL are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, "Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System." The system initiates filtered ventilation of the fuel handling building automatically following receipt of a high radiation signal or safety injection signal.

Two radiation monitoring channels (0RE-AR055 and 0RE-AR056) provide input to the FHB Ventilation System isolation. A high radiation signal from 0RE-AR055 initiates Train A FHB Ventilation System isolation. A high radiation signal from 0RE-AR056 initiates Train B FHB Ventilation System isolation. High radiation detected by any monitor initiates fuel handling building isolation and starts the FHB Ventilation System. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel handling building.

For a fuel handling accident, involving irradiated fuel assemblies other than RECENTLY IRRADIATED FUEL assemblies, the radiological dose assessments did not credit an OPERABLE FHB Ventilation System. Given the fuel handling accidents described above, the dose limits of 10 CFR 50.67 are not exceeded.

APPLICABLE SAFETY ANALYSES

The FHB Ventilation System ensures that radioactive materials in the fuel handling building atmosphere following a fuel handling accident involving RECENTLY IRRADIATED FUEL are filtered and adsorbed prior to being exhausted to the environment. This action reduces the radioactive content in the fuel handling building exhaust following a fuel handling accident so that doses remain within the limits specified in 10 CFR 50.67 (Ref. 1).

The FHB Ventilation System actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	The LCO requires two channels to ensure that the radiation monitoring instrumentation necessary to initiate the FHB Ventilation System remains OPERABLE.
APPLICABILITY	High radiation initiation of the FHB Ventilation System must be OPERABLE during movement of RECENTLY IRRADIATED FUEL assemblies in the fuel handling building to ensure automatic initiation of the FHB Ventilation System when the potential for a fuel handling accident exists. Due to radioactive decay, the FHB Ventilation System instrumentation is only required to be OPERABLE during fuel handling involving handling RECENTLY IRRADIATED FUEL. During movement of RECENTLY IRRADIATED FUEL assemblies with the containment equipment hatch not intact, the FHB Ventilation System actuation instrumentation is required to be OPERABLE to alleviate the consequences of an accident inside containment. The containment equipment hatch "not intact" refers to the requirement to have one door in the personnel air lock closed and the equipment hatch closed and held in place by a minimum of four bolts as described in the Bases for LCO 3.9.4, "Containment Penetrations." While in MODES 1, 2, 3, 4, 5, and 6 without fuel handling involving handling RECENTLY IRRADIATED FUEL in progress, the FHB Ventilation System instrumentation need not be OPERABLE since a fuel handling accident involving RECENTLY IRRADIATED FUEL cannot occur.
ACTIONS	The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

BASES

ACTIONS (continued)

A Note has been added to the ACTIONS to clarify the application of LCO 3.0.3. LCO 3.0.3 is not applicable while in MODE 5 or 6. If moving RECENTLY IRRADIATED FUEL assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving RECENTLY IRRADIATED FUEL assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of RECENTLY IRRADIATED FUEL assemblies would not be sufficient reason to require a reactor shutdown.

A.1

Condition A applies to the failure of a single radiation monitor channel. If one channel is inoperable, a period of 7 days is allowed to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this time is the same as that provided in LCO 3.7.13.

B.1, B.2.1, and B.2.2

Condition B applies if the Required Action or associated Completion Time of Condition A is not met or the failure of two radiation monitors. If the train cannot be restored to OPERABLE status, one FHB Ventilation System train must be immediately placed in the emergency mode. The FHB Ventilation System train placed in operation must be capable of being powered by an OPERABLE emergency power source. This accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation.

BASES

ACTIONS (continued)

Alternative actions may be taken if the FHB Ventilation System train is not placed in emergency mode or does not have an associated OPERABLE diesel generator. Required Action B.2.1 requires the suspension of fuel movement of RECENTLY IRRADIATED FUEL assemblies in the Fuel Handling Building, precluding a fuel handling accident. Required Action B.2.2 requires suspending movement of RECENTLY IRRADIATED FUEL assemblies inside containment, precluding an accident that would require FHB Ventilation System actuation when the equipment hatch is not intact. These actions do not preclude the movement of fuel assemblies to a safe position.

Required Action B.2.2 is modified by a Note which indicates that this Required Action is only required if the equipment hatch is not intact. If the hatch is intact, only Required Action B.2.1 is required.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which Fuel Handling Building (FHB) Radiation Actuation Functions.

SR 3.3.8.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Agreement criteria are determined, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2

A COT is performed on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FHB Ventilation System actuation. The setpoints shall be left consistent with the plant specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.3

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67.

This page intentionally left blank.

B 3.3 INSTRUMENTATION

B 3.3.9 Boron Dilution Protection System (BDPS)

BASES

BACKGROUND	The primary purpose of the BDPS is to mitigate the consequences of the inadvertent addition of unborated primary grade water into the Reactor Coolant System (RCS) when the reactor is in a shutdown condition (i.e., MODES 3, 4, and 5). The BDPS utilizes two channels of Boron Dilution Alert instrumentation. Each Volume Control Tank (VCT) Level High channel provides a signal to the associated Boron Dilution Alert alarm. CV112A divert valve not in VCT position and source range flux doubling also provide signals to the Boron Dilution Alert alarms, but these signals are not credited in the boron dilution analysis. Upon detection of a VCT Level High, an alarm is sounded to alert the operator and valve movement is manually initiated to terminate the dilution from the assumed dilution source. Valves that isolate the Refueling Water Storage Tank (RWST) are opened to supply borated water to the suction of the charging pumps, and valves which isolate the VCT are closed to terminate the assumed dilution.
APPLICABLE SAFETY ANALYSES	The BDPS senses an increases in VCT Level. The accident analyses rely on manual action to mitigate the consequences of an inadvertent boron dilution event as described in UFSAR, Chapter 15 (Ref. 1). The BDPS satisfies Criterion 2 (for the reactor coolant pump(s) and the Reactor Coolant System (RCS) loop isolation valves) and Criterion 3 (for the BDPS instrumentation) of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

LCO 3.3.9 provides the requirements for OPERABILITY of the BDPS that mitigate the consequences of a boron dilution event. Two redundant Boron Dilution Alert channels are required to be OPERABLE to provide protection against single failure. At least one Reactor Coolant Pump is required to be in operation to assure proper mixing of RCS coolant in the reactor. Without proper mixing, BDPS may be inadequate for an operator to recognize and terminate a dilution event. Each RCS loop isolation valve is required to be open since having RCS isolation valves closed presents the possibility that the isolated loop represents a dilution source that is not analyzed.

The LCO is modified by a Note that allows the Boron Dilution Alert alarm to be bypassed during reactor startup in MODE 3. Bypassing the Boron Dilution Alert alarm is acceptable during startup while in MODE 3, provided the reactor trip breakers are closed with the intent to withdraw rods for startup.

APPLICABILITY

The BDPS must be OPERABLE in MODES 3, 4, and 5 because the safety analysis identifies these requirements as necessary to enable the operator to mitigate an inadvertent boron dilution of the RCS.

The BDPS OPERABILITY requirements are not applicable in MODES 1 and 2 because an inadvertent boron dilution would be terminated by a source range trip, a trip on the Power Range Neutron Flux-High, or Overtemperature ΔT. These RTS Functions are discussed in LCO 3.3.1, "RTS Instrumentation."

In MODE 6, a dilution event is precluded by locked valves that isolate the RCS from the potential source of unborated water (refer to LCO 3.9.2, "Unborated Water Source Isolation Valves").

BASES

ACTIONS

The Actions are modified by a Note that allows the unborated water source isolation valves to be unisolated intermittently under administrative controls.

A.1

With one Boron Dilution Alert channel of the BDPS OPERABLE, Required Action A.1 requires that the inoperable channel must be restored to OPERABLE status within 72 hours. In this Condition, the remaining Boron Dilution Alert channel is adequate to alert the operator of an inadvertent boron dilution event. The 72 hour Completion Time is consistent with Engineered Safety Feature Actuation System Completion Times for loss of one redundant channel. Also, the remaining OPERABLE Boron Dilution Alert channel provides continuous indication of VCT level to the operator and has an alarm function.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unborated water source isolation valves CV111B, CV8428, CV8441, CV8435, and CV8439 are required to be closed and secured within 1 hour to prevent the flow of unborated water into the RCS. The 1 hour Completion Time takes into consideration the time to close and secure open isolation valves. The isolation valves are also required to be verified closed and secured once every 31 days. The Completion Time of "once per 31 days" is appropriate considering the fact that the isolation valves are operated under administrative controls and the remaining OPERABLE Boron Dilution Alert channel provides continuous indication of VCT level to the operator and has an alarm function.

BASES

ACTIONS (continued)

C.1, C.2, and C.3

With two Boron Dilution Alert channels inoperable, no Reactor Coolant Pump in operation, or one or more RCS loop isolation valve(s) not open, unborated water source isolation valves CV111B, CV8428, CV8441, CV8435, and CV8439 are required to be closed and secured within 1 hour to prevent the flow of unborated water into the RCS. The 1 hour Completion Time takes into consideration the time to close and secure open isolation valves. The isolation valves are also required to be verified closed and secured once every 12 hours. The Completion Time of "once per 12 hours" is appropriate considering the fact that the isolation valves are operated under administrative controls and confirms that the unborated water source isolation valves are in their correct position.

Required Action C.2 accompanies Required Actions C.1 and C.3 to verify the SDM according to SR 3.1.1.1 within 1 hour and once per 12 hours thereafter. This action is intended to confirm that no unintended boron dilution has occurred while the BDPS was inoperable, and that the required SDM has been maintained. The specified Completion Time takes into consideration sufficient time for the initial determination of SDM and other information available in the control room related to SDM.

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1 and SR 3.3.9.2

These SRs require verification that at least one Reactor Coolant Pump is in operation and the RCS loop isolation valves are open. Proper mixing of RCS coolant in the reactor cannot be assured with less than one Reactor Coolant Pump running. Without proper mixing, BDPS may be inadequate to allow the operator to recognize and terminate a dilution event. Having RCS isolation valves closed presents the possibility that the isolated loop represents a dilution source that is not analyzed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.3

Performance of the CHANNEL CHECK ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.9.4

SR 3.3.9.4 verifies that each Boron Dilution Alert channel selector switch is in the Normal position. Having the Boron Dilution Alert channel selector switch in the Normal position enables the Boron Dilution Alert alarm.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.5

Verifying the correct alignment for manual, power operated, and automatic valves in the BDPS flow path provides assurance that the proper flow paths will exist for BDPS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.9.6

SR 3.3.9.6 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.9-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the calculated normal uncertainty consistent with the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current plant specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis (Ref. 2) when applicable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.7

SR 3.3.9.7 is the performance of a CHANNEL CALIBRATION. CHANNEL CALIBRATION is a complete check of the instrument loop. This SR is modified by a Note stating that the CHANNEL CALIBRATION is only required to include that portion of the channel associated with the Boron Dilution Alert function. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.

2. WCAP-10271-P-A, Supplement 2, Revision 1, June 1990.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the departure from nucleate boiling (DNB) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature (T_{avg}) limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

BASES

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNB criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits;" LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD);" and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

Safety Analyses assumed a value of 2250 psia (2235.3 psig). The pressurizer pressure control uncertainty value assumed in the Revised Thermal Design Procedure (RTDP) is 43 psi. The Safety Analyses assumptions are bounded by the limit specified in the COLR with allowance for indication uncertainty.

Safety Analyses assumed a value of 588.0°F for the vessel average temperature.

Safety Analyses assumed a total RCS flow rate of 386,000 gpm that includes 3.5% margin for flow measurement uncertainty. This value is bounded by the LCO value of 386,000 gpm and the limit specified in the COLR which also assumes a flow measurement uncertainty of 3.5%. This 3.5% flow measurement uncertainty assumed in the analyses included errors from known sources.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO specifies limits on the monitored process Variables-pressurizer pressure, RCS average temperature (T_{avg}), and RCS total flow rate-to ensure the core operates within the limits assumed in the safety analyses. These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, based on maximum analyzed steam generator tube plugging, is retained in the LCO to assure that a lower flow rate than reviewed by the NRC will not be used. Operating within these limits will result in meeting the DNB design criterion in the event of a DNB limited transient.

A Note has been added to indicate the limit on pressurizer is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they typically represent transients initiated from power levels < 100% RTP, an increased Departure from Nucleate Boiling Ratio (DNBR) margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." LCO 3.4.1 represents the initial conditions of the safety analysis which are far more restrictive than the conditions which define the DNBR limit. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS total flow rate must be maintained during steady state operation in order to ensure DNB design criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

BASES

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust unit parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required unit conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.3

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 7 days after ≥ 90% RTP. This exception is appropriate since the heat balance requires the unit to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 7 days after reaching 90% RTP.

BASES

REFERENCES 1. UFSAR, Chapter 15.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is Moderator Temperature Coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the unit is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility Reference temperature when the reactor is critical. This parameter is also assured through compliance with LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

BASES

APPLICABLE SAFETY ANALYSES	Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for Hot Zero Power (HZP) is a process variable that is an initial condition of DBAs, such as the Rod Cluster Control Assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier. All low power safety analyses assume initial RCS loop temperatures greater than or equal to the HZP temperature of 557°F (Ref. 1). This minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during unit startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality. The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.
APPLICABILITY	In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

BASES

APPLICABILITY (continued)

The special test exception of LCO 3.1.8, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 2 with k_{eff} < 1.0 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period.

The Completion Time is reasonable, based on operating experience, to reach MODE 2 with k_{eff} < 1.0 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified ≥ 550°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.0.3.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, Inservice Leak and Hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the Reactor Coolant Pressure Boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply to the entire RCS (except the pressurizer). The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

BASES

BACKGROUND (continued)

The neutron embrittlement effect on the material toughness is reflected by increasing the Nil Ductility Reference Temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls during heatup and cooldown, respectively.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

BASES

BACKGROUND (continued)

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

BASES

LCO (continued)

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The Applicability includes MODE 6 and conditions with no fuel in the reactor vessel. This provides continued prevention of nonductile failure even while the reactor is "defueled" so that the RCS is acceptable for operation when fuel is returned to the reactor vessel. The limits do not apply to the pressurizer.

BASES

APPLICABILITY (continued)

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits;" LCO 3.4.2, "RCS Minimum Temperature for Criticality;" and Safety Limit 2.1, "Safety Limits;" also provide operational restrictions for pressure, temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4, must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an engineering evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

For the vessel beltline only, ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

BASES

ACTIONS (continued)

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the unit must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity of Required Action A.1 cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable engineering evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the unit to MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis. The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

For the vessel beltline only, ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. This SR is not required during critical operations because the combination of LCO 3.4.2 establishing a lower bound and the Safety Limits establishing an upper bound will provide adequate controls to prevent a change in excess of 100°F prior to entry into the performance condition of heatup and cooldown operations.

REFERENCES

1. WCAP-14040, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," June 1994.
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. ASTM E 185-82, July 1982.
5. 10 CFR 50, Appendix H.
6. Regulatory Guide 1.99, Revision 2, May 1988.
7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops-MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the Steam Generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a Reactor Coolant Pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses have been performed to establish the effect of flow on the Departure from Nucleate Boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

The Uncontrolled Rod Cluster Control Assembly Bank Withdrawal from a Subcritical or Low Power Startup Condition and the spectrum of Rod Cluster Control Assembly Ejection events were analyzed assuming only two of four RCPs in operation. This conservatively bounds operation in the lower modes. Analyzing these transients with only two RCPs in operation will result in a lower Departure from Nucleate Boiling Ratio (DNBR), thus producing more limiting results.

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the DNBR limit) assumes a maximum power level of 118% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 109% RTP and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The unit is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops-MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

BASES

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops-MODE 3";
LCO 3.4.6, "RCS Loops-MODE 4";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the unit to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.4.1 This SR requires verification that each RCS loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Chapter 15.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops-MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the Steam Generator (SG), to the secondary plant fluid. A secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, a Reactor Coolant Pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the Rod Control System is capable of rod withdrawal (i.e., the Reactor Trip Breakers (RTBs) are in the closed position and the Control Rod Drive Mechanisms (CRDMs) are energized) an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible (Ref. 1). Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, in MODE 3 with the Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops-MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the Rod Control System capable of rod withdrawal, two RCS loops are required to be in operation due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

When the Rod Control System is not capable of rod withdrawal, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to provide backup forced flow capability.

BASES

LCO (continued)

The Note permits all RCPs to be removed from operation (i.e., not in operation) for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow.

The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

BASES

LCO (continued)

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops-MODES 1 and 2";
LCO 3.4.6, "RCS Loops-MODE 4";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

BASES

ACTIONS

A.1

If the required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is to place the Rod Control System in a condition incapable of rod withdrawal (e.g., disable all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal. The Completion Time of 1 hour to defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

B.1 and B.2

If no RCS loop is in operation with the Rod Control System not capable of rod withdrawal, except as permitted by the Note in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended, and action to restore one RCS loop to operation must be immediately initiated. Boron dilution requires forced circulation for proper mixing.

The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to operation.

BASES

ACTIONS (continued)

C.1, C.2, and C.3

If no RCS loop is in operation with the Rod Control System capable of rod withdrawal, except as permitted by the Note in the LCO section, or if the Required Action and associated Completion Time of Condition A are not met, action must be initiated to place the Rod Control System in a condition incapable of rod withdrawal (e.g., disable all CRDMs by opening the RTBs or de-energizing the MG sets). Additionally, all operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to operation must be immediately initiated. Boron dilution requires forced circulation for proper mixing, and disabling the CRDMs removes the possibility of an inadvertent rod withdrawal.

The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to operation.

D.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

E.1

If the Required Action and associated Completion Time of Condition D are not met, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing unit conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

F.1, F.2, and F.3

If two required RCS loops are inoperable, action must be initiated to place the Rod Control System in a condition incapable of rod withdrawal (e.g., disable all CRDMs by opening the RTBs or de-energizing the MG sets). All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status must be initiated. Boron dilution requires forced circulation for proper mixing, and disabling the CRDMs removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining the capability for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification that the required operating loops are in operation. Verification may include flow rate, temperature, and pump status monitoring, which helps ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.2

SR 3.4.5.2 requires verification of required SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 18% for each required RCS loop. If the SG secondary side narrow range water level is < 18%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCP. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

UFSAR, Section 15.4.1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops-MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the Steam Generator (SG) secondary side coolant or the component cooling water via the Residual Heat Removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 4, the reactor coolant is circulated through at least two of the four RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a Reactor Coolant Pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, RHR loops can be used in lieu of RCS loops to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, circulation of the reactor coolant increases the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

RCS Loops-MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs and RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If necessary, this test may also be conducted after the initial startup testing program. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

BASES

LCO (continued)

Note 2 requires that the secondary side water temperature of each SG be < 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 350°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to provide adequate redundancy for decay heat removal.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops-MODES 1 and 2";
LCO 3.4.5, "RCS Loops-MODE 3";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

BASES

ACTIONS

A.1 and A.2

If no loop is in operation, except during conditions permitted by the Note in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to operation must be immediately initiated. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

B.1 and B.2

If one required RCS or RHR loop is inoperable and only one required loop remains OPERABLE, the intended redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

If the one required OPERABLE loop is an RHR loop and if the required loop is not restored to OPERABLE status, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, the intended redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 ($\leq$ 200°F) rather than MODE 4 (200 to 350°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

C.1 and C.2

If no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status must be initiated. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining the capability for decay heat removal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that the required operating RCS or RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.2

SR 3.4.6.2 requires verification of required SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 18% for each required RCS loop. If the SG secondary side narrow range water level is < 18%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR 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 is 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

SURVEILLANCE REQUIREMENTS (continued)

restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR 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 criteria 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 RHR 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.

RHR 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note that states the SR is not required to be performed until 12 hours after entering MODE 4. In a rapid shutdown, there may be insufficient time to verify all susceptible locations prior to entering MODE 4.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES None.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops-MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the Steam Generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the Residual Heat Removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this condition, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with the RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The second path can be another OPERABLE RHR loop or two OPERABLE SGs to provide an alternate method for decay heat removal via natural circulation.

BASES

APPLICABLE SAFETY ANALYSIS	In MODE 5, RCS circulation increases the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation and have been identified as important contributors to risk reduction. RCS Loops-MODE 5, Loops Filled, satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level ≥ 18%. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels ≥ 18%. Should the operating RHR loop fail, the SGs via natural circulation could be used to remove the decay heat. Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be < 50°F above each of the RCS cold leg temperatures before the start of a Reactor Coolant Pump (RCP) with an RCS cold leg temperature ≤ 350°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG via natural circulation has greater than or equal to the minimum water level specified in SR 3.4.7.2 and is otherwise capable of providing the necessary heat sink via natural circulation. Management of gas voids is important to RHR System OPERABILITY.

BASES

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE or the secondary side water level of at least two SGs is required to be ≥ 18%.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops-MODES 1 and 2";
LCO 3.4.5, "RCS Loops-MODE 3";
LCO 3.4.6, "RCS Loops-MODE 4";
LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If no required RHR loop is in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to operation must be immediately initiated. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

B.1 and C.1

If the required RHR loop is inoperable or the required SG(s) have secondary side water levels < 18%, redundancy for heat removal is lost. Action must be initiated immediately to restore either the required RHR loop to OPERABLE status or to restore the required SG secondary side water level(s). The Required Actions will restore an available alternate heat removal path. The immediate Completion Times reflect the importance of maintaining the availability of two paths for heat removal.

BASES

ACTIONS (continued)

D.1, D.2.1, and D.2.2

If two required RHR loops are inoperable or the required RHR loop and one or both SG secondary side water levels are not within limit(s), all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to operation must be immediately initiated or initiate action to restore required SG secondary side water level to within limits. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification that the required operating RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ≥ 18% ensures an alternate decay heat removal method via natural circulation in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE, when required, ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 18% in at least two SGs, this surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR 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 is 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 configuration, such as stand-by versus operating conditions.

The RHR 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 criteria 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 RHR 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

RHR 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation," August 28, 1995.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops-MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the Residual Heat Removal (RHR) heat exchangers. The Steam Generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport, and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation increases the time available for mitigation of an accidental boron dilution event. The RHR loops provide this circulation and have been identified as important contributors to risk reduction. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5, Loops Not Filled, satisfies Criterion 4 of 10 CFR 50.36.(c)(2)(ii).

BASES

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations.

Note 1 permits all RHR pumps to be removed from operation for ≤ 1 hour. Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation;

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction; and

c. No draining operations are permitted that would further reduce the RCS water volume.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop when these tests are safe and possible.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. Management of gas voids is important to RHR System OPERABILITY.

BASES

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops-MODES 1 and 2";
LCO 3.4.5, "RCS Loops-MODE 3";
LCO 3.4.6, "RCS Loops-MODE 4";
LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If no RHR loop is in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to operation must be immediately initiated. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal.

B.1

If only one RHR loop is OPERABLE, except during conditions permitted by Note 2, redundancy for decay heat removal is lost and action must be initiated immediately to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

BASES

ACTIONS (continued)

C.1 and C.2

If no required RHR loops are OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status. Boron dilution requires forced circulation to provide proper mixing and preserve the margin to criticality. The immediate Completion Times reflect the importance of maintaining the capability for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification that the required operating RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which helps ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.2

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR 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 is 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR 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 criteria 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 RHR 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.

RHR 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES None.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls and Engineered Safety Features (ESF) power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer during MODES 1, 2, and 3 to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

BASES

BACKGROUND (continued)

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

The pressurizer heaters are powered from the non-Class 1E buses. The pressurizer heaters are non-safety related. Plant design included a total heater capacity of 1800 kW divided into four groups, with separate controls for the proportional and backup groups. For current capacity refer to UFSAR Table 5.1-1. The non-Class 1E ESF buses servicing the pressurizer heaters can be powered from the Unit Auxiliary Transformer, the System Auxiliary Transformer (SAT), or the emergency diesel generator by closing the ESF to non-ESF crosstie breaker.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The maximum pressurizer water level limit which ensures that a steam bubble exists in the pressurizer satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, they provide the capability to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), and thus, satisfy Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 1656 cubic feet, which is equivalent to ≤ 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from redundant ESF power supplied buses. Since the only safety function for pressurizer heaters is in a loss of offsite power condition, normal power is not required for OPERABILITY. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW is derived from generic evaluation of Westinghouse pressurizer heat loss calculations (Ref. 3).

BASES

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbations, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an ESF power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1, A.2, A.3, and A.4

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the unit at steady state conditions. In MODE 1 at > 10% RTP (P-7), the unit will trip since the upper limit of this LCO is the same as the Pressurizer Water Level-High Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3, with all rods fully inserted and incapable of withdrawal. Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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 plant systems.

BASES

ACTIONS (continued)

B.1

If the required groups of pressurizer heaters are inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using the remaining pressurizer heater capability.

C.1 and C.2

If Required Action B.1 and its associated Completion Time are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 6 hours and to MODE 4 within 12 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be ≥ 150 kW. This is performed by energizing the heaters and measuring circuit current. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.3

This Surveillance demonstrates that the heaters can be manually transferred from the normal non-ESF power supply to the ESF power supply and energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.
3. Westinghouse Owners Group Study, "Emergency Power Supply Requirements for the Pressurizer Heaters," transmitted via B. L. King to C. Reed, TMI-OG-83, September 26, 1979.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODES 4 and 5, and in MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 2% tolerance requirement assumed in the safety analysis. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

BASES

BACKGROUND (continued)

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the UFSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries;

f. Locked rotor; and

g. Feedwater line break.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events c, d, and e (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The three pressurizer safety valves are set to open at 2460 psig, slightly below the RCS design pressure (2500 psia), and within the ASME specified tolerance (Ref. 4), to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 2% tolerance requirement assumed in the safety analysis. The limit protected by this Specification is the Reactor Coolant Pressure Boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

The Note allows entry into MODE 3 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

APPLICABILITY

In MODES 1, 2, and 3, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 is conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODES 4 and 5, and in MODE 6 with the reactor vessel head on, because Low Temperature Overpressure Protection (LTOP) is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

BASES

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If Required Action A.1 and its associated Completion Time are not met or if two or more pressurizer safety valves are inoperable, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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 plant systems. In MODE 4, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the INSERVICE TESTING PROGRAM. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 2% of a nominal 2460 psig for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

BASES

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. UFSAR, Chapter 15.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are air operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break Loss Of Coolant Accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

BASES

BACKGROUND (continued)

The unit has two PORVs, each having a relief capacity of 210,000 lb/hr at 2350 psia. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure-High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for Low Temperature Overpressure Protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain unit transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. If a loss of offsite power is assumed to accompany the event, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which Departure from Nucleate Boiling Ratio (DNBR) criteria are critical (Ref. 2). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. As such, this actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g. as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage.

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to automatically open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

BASES

APPLICABILITY (continued)

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODE 4, 5, or 6, when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in MODES 4 and 5, and in MODE 6 with the reactor vessel head in place.

ACTIONS

A Note has been added to clarify that all pressurizer PORVs and block valves are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the unit until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

BASES

ACTIONS (continued)

B.1, B.2 and B.3

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time of 1 hour. Because there is at least one PORV that remains OPERABLE, 72 hours is provided to restore the inoperable PORV to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the PORV cannot be restored within this time, the unit must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1, and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control (i.e., closed) to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation.

ACTIONS (continued)

Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the power will be restored, and the PORV restored to OPERABLE status. If it cannot be restored within this additional time, the unit must be brought to a MODE in which the LCO does not apply, as required by Condition D.

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed 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. In MODE 4, 5, and 6 with the reactor vessel head on, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

ACTIONS (continued)

E.1 and E.2

If two PORVs are inoperable and not capable of being manually cycled, Condition B and its associated Required Actions would already be entered. The Required Actions would either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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 plant systems. In MODE 4, 5, and 6 with the reactor vessel head on, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

F.1

If two block valves are inoperable, it is necessary to restore at least one block valve within 2 hours. The Completion Time is reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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 plant systems. In MODE 4, 5, and 6 with the reactor vessel head on, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Note modifies this SR by stating that it is not required to be met with the block valve closed in accordance with the Required Actions of this LCO. These test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status (i.e., completion of the Required Actions fulfills the SR).

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Note modifies the SR to allow entry into and operation in MODE 3 prior to performing the SR. This allows the test to be performed in MODE 3 under operating temperature and pressure conditions prior to entering MODE 1 or 2. In accordance with Reference 3, this test should be performed in MODE 3 or 4 to adequately simulate operating temperature and pressure effects on PORV operation.

SR 3.4.11.3

Operating the solenoid air control valves and check valves on the air accumulators ensures the PORV control system actuates properly when called upon. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. Regulatory Guide 1.32, February 1977.
2. UFSAR, Section 15.2.
3. Generic Letter 90-06, "Resolution of Generic Issue 70, "Power Operated Relief Valve and Block Valve Reliability," and Generic Issue 94, "Additional Low Temperature Overpressure Protection for Light Water Reactors," pursuant to 10 CFR 50.54(f), June 25, 1990.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the Reactor Coolant Pressure Boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the pressurizer Power Operated Relief Valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the MODES in which LTOP is necessary.

The reactor vessel material is less ductile at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only within the limits specified in the PTLR.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

BASES

BACKGROUND (continued)

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all Safety Injection (SI) pumps and all but one charging pump (a centrifugal charging pump) incapable of injection into the RCS and isolation of the SI accumulators. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than one centrifugal charging pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with reduced lift settings, or two Residual Heat Removal (RHR) suction relief valves, or one PORV and one RHR suction relief valve, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to prevent overpressurization for the required coolant input capability.

BASES

BACKGROUND (continued)

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure approaches a limit determined by the LTOP actuation logic. The LTOP actuation logic monitors both RCS temperature and RCS pressure and determines when a condition not acceptable in the PTLR limits is approached. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is processed through a function generator that calculates a pressure limit for that temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The PTLR presents the PORV setpoints for LTOP. The setpoints are normally staggered so only one valve opens during a low temperature overpressure transient. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

BASES

BACKGROUND (continued)

RHR Suction Relief Valve Requirements

During LTOP MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot legs to the inlets of the RHR pumps. While these valves are open, the RHR suction relief valves are exposed to the RCS and are able to relieve pressure transients in the RCS.

The RHR suction isolation valves must be open to make the RHR suction relief valves OPERABLE for RCS overpressure mitigation. The RHR suction relief valves are spring loaded, bellows type water relief valves with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires removing a pressurizer safety valve, removing a PORV's internals, and disabling its block valve in the open position, or similarly establishing any comparable vent. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. In MODE 4 and below, overpressure prevention falls to two OPERABLE RCS relief valves or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor Coolant Pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Rendering all SI pumps and all charging pumps but one centrifugal charging pump incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, "RCS Loops-MODE 4," and LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," provide this protection.

The Reference 4 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when only one centrifugal charging pump is actuated. Thus, the LCO allows only one centrifugal charging pump OPERABLE during the LTOP MODES. Since none of the overpressure protection methods can handle the pressure transient need from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR. The isolated accumulators must have their discharge valves closed and the valve power supply breakers in their open positions.

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting mass addition transient of one centrifugal charging pump injecting into a water solid RCS or the limiting heat input transient of the startup of an idle RCP with the secondary water in the steam generator $\leq$ 50°F above the RCS cold leg temperatures. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The PORV setpoints in the PTLR will be updated, as necessary, when the P/T limits are revised. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3 discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

BASES

APPLICABLE SAFETY ANALYSES (continued)

RHR Suction Relief Valve Performance

The RHR suction relief valves do not have variable pressure and temperature lift setpoints like the PORVs. Analyses must show that one RHR suction relief valve with a setpoint ≤ 450 psig will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the P/T limit curve. Assuming all relief flow requirements during the limiting LTOP event, an RHR suction relief valve will maintain RCS pressure to within the valve rated lift setpoint, plus an accumulation ≤ 10% of the rated lift setpoint.

As the RCS P/T limits are decreased to reflect the loss of toughness in the reactor vessel materials due to neutron embrittlement, the RHR suction relief valves must be analyzed to still accommodate the design basis transients for LTOP.

The RHR suction relief valves are considered active components. Thus, the failure of one valve is assumed to represent the worst case single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 2.0 square inches is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transients for the LTOP configuration, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation capability and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires no SI pumps and a maximum of one charging pump (centrifugal) be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and de-energized (when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR).

The LCO is modified by two notes. Note 1 permits operation in MODE 4 with all SI pumps and charging pumps capable of RCS injection whenever all RCS cold legs exceed 330°F. This is necessary to allow transition between MODES 3 and 4. Note 2 permits operation in MODE 5 and in MODE 6 when the reactor vessel head is on with one or more SI pumps capable of RCS injection whenever pressurizer level is ≤ 5 percent. This is necessary to provide for the mitigation of the effects of a loss of decay heat removal cooling event during mid-loop operations. Operation of at least one SI pump is required in some instances to prevent core uncovery.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs;

b. Two OPERABLE RHR suction relief valves;

c. One OPERABLE PORV and one OPERABLE RHR suction relief valve; or

d. A depressurized RCS and an OPERABLE RCS vent.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valves are open, its setpoint is ≤ 450 psig, and testing has proven its ability to open at this setpoint.

BASES

LCO (continued)

An RCS vent is OPERABLE when open with an area of ≥ 2.0 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable in MODES 4 and 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 350°F. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure resulting in little or no time available to allow operator action to mitigate the event.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and B.1

With two centrifugal charging pumps capable of injecting into the RCS, or one positive displacement charging pump capable of injecting into the RCS, or any SI pump capable of injecting into the RCS, RCS overpressurization is possible. The requirement to immediately initiate action (except during charging pump swap operation) to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

Required Action A.1 is modified by a Note that permits two charging pumps capable of RCS injection for ≤ 15 minutes to allow for pump swaps.

C.1 and D.1

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If the Required Action and associated Completion Time of Condition C are not met, Required Action D.1 must be performed in the next 12 hours. Depressurizing the accumulators below the LTOP limit from the PTLR prevents an accumulator pressure from exceeding the LTOP limits if the accumulators are fully injected.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

BASES

ACTIONS (continued)

E.1

In MODE 4, with one required RCS relief valve inoperable, the RCS relief valve must be restored to OPERABLE status within a Completion Time of 7 days. Two RCS relief valves in any combination of the PORVS and the RHR suction relief valves are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers that only one of the RCS relief valves is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 5). Thus, with one of the two RCS relief valves inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore two valves to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE RCS relief valve to protect against overpressure events.

ACTIONS (continued)

G.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RCS relief valves are inoperable; or

b. The Required Action and associated Completion Time of Condition D, E, or F is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, D, E, or F.

The vent must be sized ≥ 2.0 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the unit in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, all SI pumps and all charging pumps but one centrifugal charging pump are verified incapable of injecting into the RCS, and the accumulator discharge isolation valves are verified closed and de-energized.

The SI pumps and charging pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a mass addition event such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed. This latter method is appropriate when the SI pump needs to be available for mitigation of the effects of a loss of decay heat removal event (Ref. 6). Another alternate method of LTOP control may be utilized when a pump must be energized for testing or for filling accumulators to assure positive control of the capability for injection by the pump. This may be accomplished by closing the isolation valve and removing power from the valve operator, or by securing a manual isolation valve in the closed position. These methods are acceptable provided that an OPERABLE flow path exists from the RWST to the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.3 is modified by a Note stating that accumulator isolation is only required to be met for an accumulator if its pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

The RCS vent of ≥ 2.0 square inches is proven OPERABLE by verifying its open condition either:

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of LCO 3.4.12.d.4.

SR 3.4.12.5

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying its RHR suction isolation valves are open. This Surveillance is only required to be performed if the RHR suction relief valve is being used to satisfy this LCO.

The RHR suction isolation valves, RH8701A and RH8701B for relief valve RH8708A, and RH8702A and RH8702B for relief valve RH8708B, are verified to be opened. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The ASME Code (Ref. 7) test per INSERVICE TESTING PROGRAM verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.6

The PORV block valve must be verified open to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.7

Performance of a COT is required within 12 hours after decreasing RCS temperature to ≤ 350°F and periodically on each required PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A Note indicates that this SR is not required to be performed until 12 hours after decreasing RCS cold leg temperature to ≤ 350°F.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.8

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. ASME, Boiler and Pressure Vessel Code, Section III.
4. UFSAR, Chapter 15.
5. Generic Letter 90-06.
6. Safety Evaluation Report, dated August 31, 1990.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

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. Valves isolate connecting systems from the RCS.

During plant 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 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.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems. The leakage detection instrumentation is discussed in Section 3.4.15.

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.

A limited amount of leakage inside containment is expected from systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located (identified), and isolated in such a manner, if possible, to not interfere with detection of unidentified RCS leakage.

BASES

BACKGROUND (continued)

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). However, the ability to monitor leakage provides advance warning to permit unit shutdown before a LOCA occurs. This advantage has been shown by "leak before break" studies.

APPLICABLE SAFETY ANALYSIS

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.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a Main Steam Line Break (MSLB). The leakage contaminates the secondary fluid. Other accidents or transients involving secondary steam release to the atmosphere are the Steam Generator Tube Rupture (SGTR), Control Rod Ejection, and the Locked Rotor event (note that the Locked Rotor analysis assumes a concurrent Steam Generator (SG) Power Operated Relief Valve (PORV) failure). The MSLB is more limiting than the SGTR, Control Rod Ejection and Locked Rotor event for main control room radiation dose.

The safety analyses for the Main Steamline Break and the Locked Rotor with Failed Open PORV, base the radioactive discharge to the atmosphere on primary to secondary LEAKAGE from the faulted SG of 0.5 gallon per minute and primary to secondary LEAKAGE from the intact SGs of 0.218 gallon per minute per intact SG. For the Control Rod Ejection, the radioactive discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute. The SGTR event assumes total initial primary to secondary LEAKAGE of 1.0 gpm for the intact SGs plus the leakage rate associated with a double-ended rupture of a single tube. 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.

The UFSAR (Ref. 3) analysis for MSLB accident is postulated as a break of one of the large steam lines outside the containment leading from a SG.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For the three intact SGs loops, primary to secondary coolant leakage transfers activity into the secondary coolant. This makes it available for release into the environment via steaming through the SG PORV.

For the coolant loop with the broken steam line (i.e., faulted SG), primary to secondary coolant leakage is assumed to be released from the RCS directly into the environment without passing through any secondary coolant. This is due to assumed "dry-out" conditions in the faulted SG.

The dose consequences resulting from the MSLB, SGTR, Control Rod Ejection and Locked Rotor accidents are within the limits defined in 10 CFR 50.67 (Ref. 4).

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

LCO

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, valve seats, and gaskets is not pressure boundary LEAKAGE.

BASES

LCO (continued)

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 discharge flow 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.

BASES

LCO (continued)

d. <u>Primary to Secondary LEAKAGE through any one SG</u>

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. 5). 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.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," 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 leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included as identified LEAKAGE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greater due to RCS pressure.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

ACTIONS

<u>A.1</u>

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 Required Action is necessary to prevent further deterioration of the RCPB.

BASES

ACTIONS (continued)

B.1 and B.2

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 unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 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 plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the 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, valve seats, 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 and near operating pressure. The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant 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 (≥ 2150 psig), 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 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 LCO 3.4.15, "RCS Leakage Detection Instrumentation."

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

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 3.4.19, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 5. 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with EPRI guidelines (Ref. 6).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Chapter 15.
4. 10 CFR 50.67.
5. NEI 97-06, "Steam Generator Program Guidelines."
6. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the Reactor Coolant Pressure Boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressurization of the low pressure piping or components. Failure consequences could be a Loss Of Coolant Accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

BASES

BACKGROUND (continued)

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. PIVs are provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System;

b. Safety Injection (SI) System; and

c. Chemical and Volume Control System.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 600 psig, overpressurization failure of the RHR low pressure line could result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

RCS PIV OPERABILITY protects the low pressure systems attached to the RCS from potential failure due to overpressurization. This protection (i.e., RCS PIV OPERABILITY) is provided by both the leak tight PIVs and the RHR System suction isolation valve interlocks.

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value (Ref. 6).

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

BASES

LCO (continued)

The following valves are RCS PIVs:

Valve Number	Function
SI8900A, B, C, D	Charging/SI check valve
SI8815	Charging/SI backup check valve
SI8948A, B, C, D	Accumulator check valve
SI8956A, B, C, D	Accumulator backup check valve
SI8818A, B, C, D	RHR cold leg check valve
SI8819A, B, C, D	SI cold leg check valve
SI8949A, B, C, D	SI hot leg check valve
SI8905A, B, C, D	SI hot leg backup check valve
SI8841A, B	RHR hot leg check valve
RH8701A, B	RHR suction Motor Operated Valve (MOV)
RH8702A, B	RHR suction MOV

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that separate entry into a Condition is allowed for each flow path. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

BASES

ACTIONS (continued)

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valve used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete this Action and the low probability of a second valve failing during this period.

B.1

The inoperability of the RHR System suction isolation valve interlock could allow inadvertent opening of the valves at RCS pressures in excess of the RHR Systems design pressure. If the RHR System suction isolation valve interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one de-energized power operated valve within 4 hours. This Action accomplishes the purpose of the interlock function.

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Actions and associated Completion Times of Conditions A and B are not met, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 9 months, but may be extended, if the plant does not go into MODE 5 for at least 7 days. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Testing must also be performed prior to entering MODE 2 whenever the unit has been in MODE 5 for ≥ 7 days if leakage testing has not been performed once within the previous 9 months.

The leakage testing is typically performed at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions. However, test pressures less than 2235 psig but greater than 350 psig are allowed. When measured at these reduced pressures, observed leakage must be adjusted for the actual test pressure up to 2235 psig assuming the leakage to be directly proportional to pressure differential to the one half power.

This SR is modified by three Notes. Note 1 allows entry into MODES 3 and 4 to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. Note 1 is applicable to all Frequencies of this Surveillance.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless it has been established (per Note 2) that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated if in MODE 1 or 2, or prior to entry into MODE 2 if not in MODE 1 or 2 at the end of the 24 hour period. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

Note 3 exempts the RHR suction isolation valves (RH8701A and B and RH8702A and B) from the specified Frequency of this testing since these MOVs are not subject to the same failure characteristics as a check valve that has actuated due to flow.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.14.2

The interlock setpoint that prevents the RHR System suction isolation valves from being opened is set so the actual RCS pressure must be < 360 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded and the RHR relief valves will not lift. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.
5. NUREG-0677, May 1980.
6. EG&G Report, EGG-NTAP-6175.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45, Revision 0, (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect significant Reactor Coolant Pressure Boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms.

The containment sump, used to collect unidentified LEAKAGE, is instrumented to identify leakages of 1.0 gpm within one hour.

The reactor coolant contains radioactivity that, when released to the containment, may be detected by radiation monitoring instrumentation. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

Other indications may be used to detect an increase in unidentified LEAKAGE; however, they are not required to be OPERABLE by this LCO.

BASES

BACKGROUND (continued)

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during unit operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements is affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

The above-mentioned LEAKAGE detection methods or systems differ in sensitivity and response time. Some of these systems could serve as early alarm systems signaling the operators that closer examination of other detection systems is necessary to determine the extent of any corrective action that may be required.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary.

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

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified leakage are detected in time to allow actions to place the unit in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation. The RCS leak detection instrumentation required by this TS supports the Leak-Before-Break licensing basis (Ref. 4).

This LCO requires two instruments to be OPERABLE.

The containment sump is used to collect unidentified LEAKAGE. The LCO requirements apply to the total amount of unidentified LEAKAGE collected in the sump. The containment floor drain sump flow monitor (RF008) and the reactor cavity sump flow monitor (RF010) are normally utilized to fulfill the containment sump monitor requirement. Alarms are provided to alert the operator of leakages of 1.0 gpm. When the alarm function is not capable of detecting 1.0 gpm of unidentified LEAKAGE within one hour, the containment floor drain sump flow indication may be periodically monitored to ensure the capability of detecting 1.0 gpm of unidentified LEAKAGE within one hour.

In lieu of the containment floor drain sump flow monitor (RF008), either containment sump level monitor (PC002 or PC003) can be used by monitoring a change in sump level over a period of time in such a manner as to ensure the capability of detecting 1.0 gpm of unidentified LEAKAGE within one hour. For Byron Unit 2 only, the containment sump level monitors (PC002 and PC003) also have the ability to provide an alarm to alert the operator of leakages of 1.0 gpm.

The identification of unidentified LEAKAGE will be delayed by the time required for unidentified LEAKAGE to travel to the containment sump and it may take longer than one hour to detect unidentified LEAKAGE of 1.0 gpm, depending on the origin and magnitude of the LEAKAGE. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by the gaseous (PR011B) or particulate (PR011A) containment atmosphere radioactivity monitor. Only one of the two detectors is required to be OPERABLE. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE, but have recognized limitations. Reactor coolant radioactivity levels will be low during

BASES

LCO (continued)

initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitor to detect 1.0 gpm increase within one hour during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting 1.0 gpm increase in unidentified LEAKAGE within one hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (UFSAR Table 11.1-4).

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitor, in combination with a gaseous or particulate radioactivity monitor, provides an acceptable minimum.

BASES

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the containment atmosphere radioactivity monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

BASES

ACTIONS (continued)

B.1.1, B.1.2, and B.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitor.

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1 and C.2

With the required containment sump monitor inoperable, the only means of detecting LEAKAGE is the required containment atmosphere radioactivity monitor. A Note clarifies that this Condition is applicable when the only OPERABLE monitor is the containment atmosphere gaseous radioactivity monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1.0 gpm leak within one hour when RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the containment atmosphere must be taken to provide alternate periodic information. The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7 day Completion Time ensures that the unit will not be operated in a degraded configuration for a lengthy time period.

BASES

ACTIONS (continued)

D.1 and D.2

If a Required Action and associated Completion Time of Condition A, B or C is not met, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

E.1

With all required monitors inoperable, no means of monitoring leakage are available, and immediate actions, in accordance with LCO 3.0.3, are required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test consists of exercising the digital computer hardware using data base manipulation and injecting simulated process data to verify OPERABILITY of alarm and trip functions. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.3 and SR 3.4.15.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. Regulatory Guide 1.45, Revision 0, “Reactor Coolant Pressure Boundary Leakage Detection Systems,” May 1973.
3. UFSAR, Section 5.2.5.
4. Safety Evaluation Regarding Leak-Before-Break Analysis - Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, dated October 25, 1996.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND	For the bounding accidents specified in Regulatory Guide (RG) 1.183 (Ref. 1), 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. 2). 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. For other non-bounding transients and accidents analyzed in the Updated Final Safety Analysis Report (UFSAR), the maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 3). Any future modification to the facility design bases for these events will use source term assumptions and radiological criteria in the affected analyses that are established in RG 1.183 and 10 CFR 50.67. The RCS specific activity 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 main steam line break (MSLB) 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. 4).
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 SRP acceptance criteria following a MSLB or SGTR accident. The safety analyses (Refs. 5 and 6) assume the specific activity of the reactor coolant is at the LCO limits. For the MSLB accident, the safety analysis assumes the primary to secondary LEAKAGE from the faulted steam generator (SG) is 0.5 gallon per minute and the primary to secondary LEAKAGE from the intact SGs is 0.218 gallon per minute per intact SG. The SGTR event assumes

APPLICABLE SAFETY ANALYSES (continued)

initial primary to secondary LEAKAGE is 1.0 gpm for the intact SGs plus the leakage rate associated with a double-ended rupture of a single tube. The LCO 3.4.13 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 analyses. 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 3.7.3, "Secondary Specific Activity."

The analyses for the MSLB 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 MSLB (by a factor of 500), or SGTR (by a factor of 335), respectively. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to an iodine spike caused by a reactor or an RCS transient prior to the accident. In both cases, the noble gas specific activity is assumed to be 603 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. 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. 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 MSLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment. Reactor trip for MSLB occurs after the generation of an overpower ΔT trip signal. The affected SG blows down completely and steam is vented directly to the atmosphere. 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 60.0 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 603 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. 4). The MSLB and SGTR accident analyses (Refs. 5 and 6) 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 MSLB or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 4).

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of a MSLB or SGTR to within the SRP acceptance criteria (Ref. 4).

In MODES 5 and 6, 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

A.1 and A.2

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 ≤ 60.0 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.

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 MSLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S), relying on Required Actions A.1 and A.2 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.

B.1

With the DOSE EQUIVALENT XE-133 greater than the LCO limit, DOSE EQUIVALENT XE-133 must be restored to within limit within 48 hours. The allowed 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 MSLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODES(S), relying on Required Action B.1 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.

BASES

Actions (continued)

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 is > 60.0 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The 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.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. 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 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 the SR 3.4.16.1 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.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.

REFERENCES

1. Regulatory Guide 1.183, dated July 2000.
2. 10 CFR 50.67.
3. 10 CFR 100.11.
4. Standard Review Plan (SRP) Section 15.0.1 "Radiological Consequence Analyses Using Alternative Source Terms," Rev. 0.
5. UFSAR, Section 15.1.5.
6. UFSAR, Section 15.6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 RCS Loop Isolation Valves

BASES

BACKGROUND

The RCS may be operated with loops isolated in order to perform maintenance. While operating with a loop isolated, there is potential for inadvertently opening the isolation valves in the isolated loop. In this event, the coolant in the isolated loop would suddenly begin to mix with the coolant in the unisolated portion of the RCS. This situation has the potential of causing a positive reactivity addition with a corresponding reduction of SDM if:

a. The temperature in the isolated loop is lower than the temperature in the unisolated portion of the RCS (cold water incident); or

b. The boron concentration in the isolated loop is lower than the boron concentration required in the RCS to meet SDM (boron dilution incident).

As discussed in the UFSAR (Ref. 1), the startup of an isolated loop is performed in a controlled manner that virtually eliminates any sudden positive reactivity addition from cold water or boron dilution because:

a. LCO 3.4.18, "RCS Isolated Loop Startup," and plant operating procedures require that the boron concentration in the isolated loop be maintained higher than the required SDM boron concentration of the unisolated portion of the RCS, thus eliminating the potential for introducing coolant from the isolated loop that could dilute the boron concentration in the unisolated portion of the RCS to less than the required SDM boron concentration;

b. The cold leg loop isolation valve cannot be opened unless the temperatures of both the hot and cold legs of the isolated loop are within 20°F of the temperatures of the hot and cold legs of the unisolated portion of the RCS (compliance is ensured by operating procedures and automatic interlocks); and

BASES

BACKGROUND (continued)

c. Other automatic interlocks, all of which are part of the Reactor Protection System (RPS), prevent opening the hot leg loop isolation valve unless the cold leg loop isolation valve is fully closed.

APPLICABLE SAFETY ANALYSES

During startup of an isolated loop in accordance with LCO 3.4.18, the cold leg loop isolation valve interlocks and operating procedures prevent opening of the valve until the isolated loop and unisolated portion of the RCS boron concentrations and temperatures are within limits. This ensures that any undesirable reactivity effect from the isolated loop does not occur.

The safety analyses assume a minimum SDM as an initial condition for Design Basis Accidents (DBAs) (Ref. 1). Violation of the LCO, combined with mixing of the isolated loop coolant into the unisolated portion of the RCS, could result in the SDM being less than that assumed in the safety analyses.

The above analyses are for DBAs that establish the acceptance limits for the RCS loop isolation valves. Reference to the analyses for these DBAs is used to assess changes to the RCS loop isolation valves as they relate to the acceptance limits.

The boron concentration of an isolated loop may affect SDM and therefore RCS loop isolation valves satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO ensures that a loop isolation valve that becomes closed in MODES 1 through 4 is fully isolated and the plant placed in MODE 5. Loop isolation valves are used for performing maintenance when the plant is in MODE 5 or 6, and startup of an isolated loop is covered by LCO 3.4.18.

This LCO also ensures that loop isolation valves remain open in MODES 1, 2, 3, and 4. Closure of the loop isolation valves during these MODES results in the potential for an inadvertent startup of an isolated loop which could result in the SDM being less than assumed in the safety analyses.

APPLICABILITY

In MODES 1 through 4, this LCO is applicable since unisolating an isolated loop has not been analyzed. The potential affects (with a boron concentration or temperature less than that of the unisolated portion of the RCS) may include an inadvertent criticality.

In MODES 5 and 6, the SDM of the operating loops is large enough to permit operation with isolated loops. In these MODES, controlled startup of isolated loops is possible without significant risk of inadvertent criticality.

BASES

ACTIONS

The Actions have been provided with a Note to clarify that all RCS loop isolation valves for this LCO are treated as separate entities, each with separate Completion Times, (i.e., the Completion Time is on a component basis).

A.1

If power is inadvertently restored to one or more loop isolation valve operators, the potential exists for accidental isolation of a loop with a subsequent inadvertent startup of the isolated loop. The loop isolation valves have motor operators. Therefore, these valves will maintain their last position when power is removed from the valve operator. With power applied to the valve operators, only the interlocks prevent the valve from being operated. Although operating procedures and interlocks make the occurrence of this event unlikely, the prudent action is to remove power from the loop isolation valve operators. The Completion Time of 30 minutes to remove power from the loop isolation valve operators is sufficient considering the complexity of the task.

B.1, B.2, and B.3

Should a loop isolation valve be closed in MODES 1 through 4, the affected loop must be fully isolated immediately and the unit placed in MODE 5 to preclude inadvertent startup of the loop and the potential inadvertent criticality. Required Actions B.2 and B.3 require placing the unit in MODE 3 within 6 hours and MODE 5 within 36 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.17.1 The Surveillance is performed to ensure that the RCS loop isolation valves are open, with power removed from the loop isolation valve operators. The primary function of this Surveillance is to ensure that power is removed from the valve operators, since SR 3.4.4.1 of LCO 3.4.4, "RCS Loops-MODES 1 and 2," ensures that the loop isolation valves are open by verifying that all loops are operating and circulating reactor coolant. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 15.4.4.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 RCS Loops-Isolated

BASES

BACKGROUND

The RCS may be operated with loops isolated in MODES 5 and 6 in order to perform maintenance. While operating with a loop isolated, there is potential for inadvertently opening the isolation valves in the isolated loop. In this event, the coolant in the isolated loop would suddenly begin to mix with the coolant in the unisolated portion of the RCS. This situation has the potential of causing a positive reactivity addition with a corresponding reduction of SDM if

a. The temperature in the isolated loop is lower than the temperature in the unisolated portion of the RCS (cold water incident); or

b. The boron concentration in the isolated loop is lower than the boron concentration required in the RCS to meet SDM (boron dilution incident).

As discussed in the UFSAR (Ref. 1), the startup of an isolated loop is done in a controlled manner that virtually eliminates any sudden positive reactivity addition from cold water or boron dilution because:

a. This LCO and plant operating procedures require that the boron concentration in the isolated loop be maintained higher than the required SDM boron concentration of the unisolated portion of the RCS, thus eliminating the potential for introducing coolant from the isolated loop that could dilute the boron concentration in the unisolated portion of the RCS to less than the required SDM boron concentration;

b. The cold leg loop isolation valve cannot be opened unless the temperatures of both the hot leg and cold leg of the isolated loop are within 20°F of the unisolated portion of the RCS. Compliance with the temperature requirement is ensured by operating procedures and automatic interlocks; and

BASES

BACKGROUND (continued)

c. Other automatic interlocks prevent opening the hot leg loop isolation valve unless the cold leg loop isolation valve is fully closed. All of the interlocks are part of the Reactor Protection System,

APPLICABLE SAFETY ANALYSES

During startup of an isolated loop, the cold leg loop isolation valve interlocks and operating procedures prevent opening the valve until the isolated loop and unisolated portion of the RCS boron concentrations and temperatures are within limits. This ensures that any undesirable reactivity effect from the isolated loop does not occur.

The safety analyses assume a minimum SDM as an initial condition for Design Basis Accidents. Violation of this LCO could result in the SDM being reduced in the operating loops to less than that assumed in the safety analyses.

The boron concentration of an isolated loop may affect SDM and therefore RCS isolated loop startup satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Loop isolation valves are used for performing maintenance when the unit is in MODE 5 or 6. This LCO ensures that the loop isolation valves remain closed until the differentials of temperature and boron concentration between the unisolated portion of the RCS and the isolated loops are within acceptable limits.

APPLICABILITY

In MODES 5 and 6, the SDM of the unisolated portion of the RCS is large enough to permit operation with isolated loops. In these MODES, controlled startup of isolated loops is possible without significant risk of inadvertent criticality. In MODES 1, 2, 3, and 4, operation with isolated loops is not permitted. See LCO 3.4.17, "RCS Loop Isolation Valves."

BASES

ACTIONS

A.1 and B.1

Required Action A.1 and Required Action B.1 assume that the prerequisites of the LCO are not met and a loop isolation valve has been inadvertently opened. Therefore, the Actions require immediate closure of isolation valves to preclude a boron dilution event or a cold water event.

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

This Surveillance is performed to ensure that the temperature differential between the isolated loop and the unisolated portion of the RCS is ≤ 20°F. Performing the Surveillance 30 minutes prior to opening the cold leg isolation valve in the isolated loop provides reasonable assurance, based on engineering judgment, that the temperature differential will stay within limits until the cold leg isolation valve is opened. This Frequency has been shown to be acceptable through operating experience.

SR 3.4.18.2

To ensure that the boron concentration of the isolated loop is greater than or equal to the boron concentration required in the RCS to meet SDM, a Surveillance is performed 4 hours prior to opening either the hot or cold leg isolation valve. Performing the Surveillance 4 hours prior to opening either the hot or cold leg isolation valve provides reasonable assurance the resulting boron concentration difference will be within acceptable limits when the loop is unisolated. This Frequency is acceptable due to the amount of time required to sample and confirm concentration results.

REFERENCES

1. UFSAR, Section 15.4.4.

This page intentionally left blank.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.19 Steam Generator (SG) Tube Integrity

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 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

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 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, 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 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSIS

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 a SGTR event assumes total initial primary to secondary LEAKAGE of 1.0 gpm for the intact SGs plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via the SG Power Operated Relief Valves (PORVs).

The analysis 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). For the Main Steamline Break and the Locked Rotor with Failed Open PORV, the radioactive discharge to the atmosphere is based on primary to secondary LEAKAGE from the faulted SG of 0.5 gallon per minute and primary to secondary LEAKAGE from the intact SGs of 0.218 gallon per minute per intact SG. For the Rod Cluster Control Assembly Ejection, the radioactive discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific 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 the NRC approved licensing basis (e.g., a fraction of these limits).

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

BASES

LCO

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, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Unit 2, the portion of the tube below 14.01 inches from the top of the tubesheet is excluded. 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 5.5.9, "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 (i.e., primary to secondary 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 have a significant effect on burst or collapse.

BASES

LCO (continued)

In that context, the term "significant" 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. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

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 induced leakage requirement of 1 gpm for all SGs bounds the accident analysis assumptions for primary to secondary LEAKAGE. 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 LCO 3.4.13, "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.

BASES

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 in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, 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.

<u>A.1 and A.2</u>

Condition A 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 3.4.19.2. 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, Condition B applies.

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

BASES

ACTIONS (continued)

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection, whichever occurs first, 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 entering MODE 4 following the next refueling outage or SG inspection, whichever occurs first. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1

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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 3.4.19.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). 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 5.5.9 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 5.5.9 until subsequent inspections support extending the inspection interval.

SR 3.4.19.2

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 5.5.9 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 provides 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 entering MODE 4 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.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 50.67.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a Loss Of Coolant Accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of Safety Injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

BASES

BACKGROUND (continued)

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves are interlocked by P-11 with the pressurizer pressure measurement channels to ensure that the valves will automatically open as RCS pressure increases to above the permissive circuit P-11 setpoint.

This interlock also prevents inadvertent closure of the valves during normal operation prior to an accident. The valves will automatically open, however, as a result of an SI signal. These features ensure that the valves meet the requirements of the Institute of Electrical and Electronic Engineers (IEEE) Standard 279-1971 (Ref. 1) for "operating bypasses" and that the accumulators will be available for injection without reliance on operator action.

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Refs. 2 and 3). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and centrifugal charging pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the centrifugal charging pumps become solely responsible for terminating the temperature increase.

BASES

APPLICABLE SAFETY ANALYSES (continued)

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 4) will be met following a LOCA:

a. During a small break Loss Of Coolant Accident (LOCA) maximum fuel element cladding temperature is ≤ 2200°F and during a large break LOCA there must be a high level of probability that maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For the small break LOCA analyses, a nominal contained accumulator water volume is used. For the large break LOCA analyses, a contained accumulator water volume range of 920 ft^3 - 980 ft^3 is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. For small breaks, the peak clad temperature is not sensitive to the accumulator water volume. For large breaks, there are two competing effects regarding accumulator water volume: the amount of water available for injection versus the injection rate. A higher water volume results in a larger total injection but at a slower injection rate. Conversely, a lower water volume results in a smaller total injection but at a faster injection rate.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both the large and the small break LOCA analyses model the pipe water volume from the accumulator to the SI accumulator discharge header downstream cold leg injection check valve (SI8948). However, an evaluation was performed neglecting the pipe water volume between the SI accumulator discharge header upstream cold leg injection check valve (SI8956) to the SI accumulator discharge header downstream cold leg injection check valve (SI8948) to address gas accumulation. This evaluation determined that the impact on peak clad temperature was minimal for both the large break and the small break LOCA analyses. Since the range of the allowed accumulator volumes is relatively small and has a minimal effect on peak clad temperature, a nominal water volume is used in the small break LOCA analysis. The small break LOCA analysis assumes a nominal water volume of 7106 gallons based on the Technical Specification (TS) minimum and maximum limits of 6995 gallons (935 ft^3, 31% of indicated level) and 7217 gallons (965 ft^3, 63% of indicated level). The large break LOCA analysis assumes a water volume range of 6882 gallons (920 ft^3, 15% of indicated level) to 7331 gallons (980 ft^3, 79% of indicated level) which bounds the TS limits.

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The large break LOCA analyses are performed at a nitrogen cover pressure range of 587 psia to 692 psia. The maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 2 and 3).

The accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 4) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open with power removed, a contained volume ≥ 31% and ≤ 63% (6995 gallons to 7217 gallons) with a boron concentration ≥ 2200 ppm and ≤ 2400 ppm, and a nitrogen cover pressure ≥ 602 and ≤ 647 psig, must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 4) limit of 2200°F.

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis demonstrates that the accumulators do not discharge following a large main steam line break. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 1 hour. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 1 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the unit to a LOCA under these conditions.

BASES

ACTIONS (continued)

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 6 hours and RCS pressure reduced to ≤ 1000 psig within 12 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 plant systems.

D.1

If more than one accumulator is inoperable, the unit is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.2 and SR 3.5.1.3

Borated water level and nitrogen cover pressure are verified for each accumulator. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator since the static design of the accumulators limits the ways in which the concentration can be changed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.5

Sampling the affected accumulator within 6 hours after a 1% volume increase (nominally 70 gallons or 10% of indicated level) will identify whether inleakage has caused a reduction in boron concentration to below the required limit. It is not necessary to verify boron concentration of the accumulator after a 1% volume increase (10% indicated level increase) if the added water inventory is from the Refueling Water Storage Tank (RWST) and the boron concentration of the RWST is ≥ 2200 ppm and ≤ 2400 ppm. With the water contained in the RWST within the boron concentration requirements of the accumulators, any added inventory would not cause the accumulator's boron concentration to exceed the limits of this LCO.

With the only indication available to the operators in the control room being level indication in percent, a required accumulator volume increase of 1% or an increase of 10% of indicated level would require the accumulator to be sampled to verify the accumulator boron concentration is within the limits. The small break LOCA analysis assumes a nominal water volume of 7106 gallons based on the TS minimum and maximum limits of 6995 gallons (935 ft^3, 31% of indicated level) and 7217 gallons (965 ft^3, 63% of indicated level). These volumes are also indicated in the specific tank curves for the SI accumulators. The large break LOCA analysis assumes a water volume range of 6882 gallons (920 ft^3, 15% of indicated level) to 7331 gallons (980 ft^3, 79% of indicated level) which bounds the TS limits. The 10% indicated level increase is considered a conservative indication for a 70 gallon increase in the accumulator volume requiring an increase in the sampling requirement to verify accumulator boron concentration remains within the specified limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.6

Verification that power is removed from each accumulator isolation valve operator ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA.

The power to the accumulator motor operated isolation valves is removed by opening the motor control center breaker and tagging it out administratively. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. IEEE Standard 279-1971.
2. UFSAR, Chapter 15.
3. UFSAR, Chapter 6.
4. 10 CFR 50.46.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS-Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss Of Coolant Accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam Generator Tube Rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the Refueling Water Storage Tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for cold leg recirculation. After approximately 6.0 hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

BASES

BACKGROUND (continued)

The ECCS consists of three separate subsystems: centrifugal charging (high head), Safety Injection (SI) (intermediate head), and Residual Heat Removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the centrifugal charging pumps, the RHR pumps, heat exchangers, and the SI pumps. Each of the three subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a single suction header supplies water from the RWST to the ECCS pumps. Separate piping supplies each subsystem and each train within the subsystem. The discharge from the centrifugal charging pumps combines prior to dividing into four supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the SI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Control valves are set to balance the flow to the RCS. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the centrifugal charging pumps supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

BASES

BACKGROUND (continued)

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps then supply the other ECCS pumps. Initially, recirculation is through the same paths as the injection phase, i.e., through the cold legs. After approximately 6.0 hours, the ECCS flow is shifted to the hot legs.

The centrifugal charging subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a Main Steam Line Break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency Diesel Generators (DGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators, the RWST, and the containment recirculation sump(s), are covered in LCO 3.5.1, "Accumulators," LCO 3.5.4, "Refueling Water Storage Tank (RWST)," and LCO 3.6.8, "Containment Sump," and provide the cooling water necessary to meet GDC 35 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. During a small break LOCA maximum fuel element cladding temperature is ≤ 2200°F and during a large break LOCA there must be a high level of probability that maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Ref. 3). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The centrifugal charging pumps and SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the centrifugal charging pumps. The SGTR and MSLB events also credit the centrifugal charging pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. For the large break LOCA event, the ASTRUM methodology examines LOOP and no-LOOP cases with a single failure disabling one train of SI pumps. No failure of containment heat removal system is modeled; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the centrifugal charging and SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For smaller LOCAs, the centrifugal charging pump delivers sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of a centrifugal charging subsystem, an SI subsystem, and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and automatically transferring suction to the containment sump.

BASES

LCO (continued)

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS hot and cold legs. Management of gas voids is important to ECCS OPERABILITY.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

The LCO is modified by two Notes that allow isolation of both SI pump flow paths and a portion of both RHR flow paths for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1 during MODE 3. Isolation of the discharge flow paths of both SI pumps may be accomplished by closing valve SI8835. Isolation of a portion of the discharge flow paths of both RHR pumps may be accomplished by closing either valve SI8809A or SI8809B. With a portion of both RHR flow paths isolated, an alternate means of cold leg injection must be available for each isolated flow path. An alternate means may include: 1) OPERABLE accumulators with their isolation valves either closed, but energized, or open; 2) cold leg injection via the Safety Injection pumps, and the SI8821A/B and the SI8835 valves; or 3) cold leg injection via the Centrifugal Charging pumps and the SI8801A/B valves.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

BASES

APPLICABILITY (continued)

This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS-Shutdown."

In MODES 5 and 6, unit conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

A.1 and B.1

With one ECCS train inoperable, 100% of the ECCS flow is provided by the remaining OPERABLE ECCS train. Required Action A.1 requires that the inoperable train be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The 7 day Completion Time is based on a probabilistic risk assessment evaluation (Refs. 6 and 7) which concludes that the Completion Time does not significantly affect the overall probability of core damage.

With two ECCS trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, Required Action B.1 requires that one train be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or their required supporting systems are not available.

ACTIONS (continued)

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of these Conditions is to maintain a combination of equipment (i.e., at least one train of each centrifugal charging subsystem, SI subsystem, and RHR subsystem, including an RHR heat exchanger) such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in unit operations under circumstances when components in opposite trains are inoperable.

Reference 10 describes situations in which one mis-positioned component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered. Energization of one or more of the valves listed in SR 3.5.2.1 does not make either train of ECCS unavailable and does not cause a loss of function provided the valve(s) is in its proper position and is capable of performing its required functions after event initiation.

<u>C.1 and C.2</u>

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 4 within 12 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper motor operated valve position ensures that the injection flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in Reference 8, that can disable the function of both ECCS trains and invalidate the accident analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position (e.g., the valves listed in SR 3.5.2.1 and SR 3.5.2.7), since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3

ECCS piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is 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 ECCS 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 is 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 configuration, such as stand-by versus operating conditions.

The ECCS 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 criteria 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 ECCS 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.

ECCS 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. This SR is specified in the INSERVICE TESTING PROGRAM. The ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.5

This Surveillance demonstrates that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal (a coincident RWST Level Low-Low signal is required to open the containment sump isolation valves). This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the INSERVICE TESTING PROGRAM.

SR 3.5.2.6

This Surveillance demonstrates that each ECCS pump starts on receipt of an actual or simulated SI signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the INSERVICE TESTING PROGRAM.

SR 3.5.2.7

Realignment of valves in the flow path on an SI signal is necessary for proper ECCS performance. These valves have mechanical stops to allow proper positioning for restricted flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. UFSAR, Section 15.6.5.
4. UFSAR, Section 6.2.1.
5. NRC Memorandum to V. Stello, Jr., from R. L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. Byron Generating Station Limiting Conditions for Operation Relaxation Program, dated April 1984.
7. WCAP-10526, "Limiting Conditions for Operation Relaxation Program."
8. NUREG-1002, "Safety Evaluation Report Related to Operation of Braidwood Station, Units 1 and 2," November 1983.
9. Deleted
10. NRC Information Notice No. 87-01.

This page intentionally left blank.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS-Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS-Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: centrifugal charging (high head) and Residual Heat Removal (RHR) (low head).

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the Refueling Water Storage Tank (RWST) and the containment recirculation sump can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic Safety Injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of a centrifugal charging subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS hot and cold legs. Management of gas voids is important to ECCS OPERABILITY.

Due to the potential for flashing/steam voiding of RHR hot leg suction piping to occur when the RCS hot leg temperature is greater than 200°F and the RHR train is realigned to the containment sump (Refs. 2 and 3), one RHR train must remain aligned for the ECCS mode of operation in MODE 4 to satisfy LCO 3.5.3 when RCS hot leg temperature is greater than 200°F.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, unit conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the unit is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the unit to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With no ECCS centrifugal charging subsystem OPERABLE, due to the inoperability of the centrifugal charging pump or flow path from the RWST, the unit is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one centrifugal charging subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the unit in MODE 5, where an ECCS train is not required.

BASES

ACTIONS (continued)

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

1. The applicable references from Bases 3.5.2 apply.
2. NRC Information Notice 2010-11.
3. Westinghouse NSAL-09-8.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling pool during refueling, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies both trains of the ECCS and the Containment Spray System through separate, redundant supply headers during the injection phase of a Loss Of Coolant Accident (LOCA) recovery. A motor operated isolation valve is provided in each header to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump following receipt of the RWST Level-Low Low (LO-2) signal. Use of a single RWST to supply both trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

The switchover from normal operation to the injection phase of ECCS operation requires changing centrifugal charging pump suction from the CVCS Volume Control Tank (VCT) to the RWST through the use of isolation valves. Each set of isolation valves is interlocked so that the VCT isolation valves will begin to close once the RWST isolation valves are fully open. Since the VCT is under pressure, the preferred pump suction will be from the VCT until the tank is isolated. This will result in a delay in obtaining the RWST borated water. The effects of this delay are discussed in the Applicable Safety Analyses section of these Bases.

During normal operation in MODES 1, 2, and 3, the Safety Injection (SI) and Residual Heat Removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

BASES

BACKGROUND (continued)

When the suction for the ECCS and Containment Spray System pumps is transferred to the containment sump, the RWST flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ECCS pumps.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling;

c. The reactor remains subcritical following a LOCA; and

d. The RWST contains a sufficient boron concentration to ensure that negative reactivity is available to limit the subsequent return to power following a Main Steam Line Break (MSLB).

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of shutdown margin or excessive boric acid precipitation in the core following the LOCA. In addition, improper boron concentrations could adversely affect the pH of the sump following the LOCA which can adversely impact iodine concentrations for offsite doses, stress corrosion cracking of equipment inside containment, and hydrogen production. Finally, improper boron concentrations could adversely affect the pH of the containment spray which can also adversely impact iodine concentrations for offsite doses (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Refs. 2 and 3). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS-Operating"; B 3.5.3, "ECCS-Shutdown"; and B 3.6.6, "Containment Spray and Cooling Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the MSLB analysis and ensures that negative reactivity is available to limit the subsequent return to power following an MSLB. The minimum boron concentration limit is also an important assumption in ensuring the reactor remains subcritical following a LOCA. The maximum boron concentration is an explicit assumption in the inadvertent ECCS actuation analysis, although it is typically a nonlimiting event and the results are very insensitive to boron concentrations. The maximum temperature ensures that the amount of cooling provided from the RWST during the heatup phase of a feedline break is consistent with safety analysis assumptions; the minimum is an assumption in both the MSLB and inadvertent ECCS actuation analyses, although the inadvertent ECCS actuation event is typically nonlimiting.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSLB analysis has considered a delay associated with the interlock between the VCT and RWST isolation valves, and the results show that the departure from nucleate boiling design basis is met. The delay has been established as 27 seconds, with offsite power available, or 37 seconds without offsite power. This response time includes 2 seconds for electronics delay, a 15 second stroke time for the RWST valves, and a 10 second stroke time for the VCT valves.

For a large break LOCA analysis, the lower boron concentration limit of 2300 ppm and a conservative calculation of the minimum RWST volume between the low level setpoint and the low low level setpoint are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The containment analysis and the calculation of the minimum post-LOCA sump pH also use the minimum water volume limit to determine a minimum available RWST volume for calculating the time until recirculation for safety injection and containment spray. Finally, the minimum sump flooding analysis, which ensures sufficient Net Positive Suction Head in the sump for recirculation, uses the minimum water volume limit to determine a minimum available RWST volume.

The upper limit on boron concentration of 2500 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 35°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure. The reduced containment pressure lowers the quality of steam exiting the break thus decreasing the rate which the steam is vented to the containment atmosphere. The decreased rate of steam vented to the containment atmosphere results in a corresponding decrease in the rate the Reactor Coolant System pressure drops and the rate ECCS fluid is injected in the core thereby causing a rise in peak clad temperature. The upper temperature limit of 100°F is used in the small break LOCA analysis and containment OPERABILITY analysis. Exceeding this temperature will result in a higher peak clad temperature, because there is less heat transfer from the core to the injected water for the small break LOCA and higher containment pressures due to reduced containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

The limits on RWST level and boron concentration also ensure that the post-LOCA sump pH will be between 8.0 and 11.0. The minimum and maximum pH values are verified for each fuel cycle using conservative maximum and minimum RWST volumes and the maximum and minimum allowed RWST boron concentrations. The LOCA offsite dose analysis assumes a conservatively low sump pH for the re-evolution of iodine from the sump. Ensuring that the minimum sump pH is at least 8.0 protects mechanical components and equipment inside containment from the effects of chloride induced stress corrosion cracking. Ensuring that the maximum sump pH is no greater than 11.0 limits the production of hydrogen due to the corrosion of aluminum and zinc inside containment. Finally, the limits on RWST boron concentration also ensure that the containment spray pH is acceptable. The calculation of the iodine removal effectiveness of the containment spray assumes a conservatively low containment spray pH.

The RWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and Containment Spray System pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits (including vent path) established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. In MODES 5 and 6, the ECCS and Containment Spray System are not required to be OPERABLE. Therefore, the RWST is not required to be OPERABLE in MODES 5 and 6 to support the ECCS and Containment Spray System.

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

BASES

ACTIONS (continued)

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the unit in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified to be within the limits assumed in the accident analyses band. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.2

Heat traced portions of the RWST vent path should be verified to be within the temperature limit needed to prevent ice blockage and subsequent vacuum formation in the tank during rapid level decreases caused by accident conditions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when the ambient air temperature is ≥ 35°F. With ambient air temperature above this limit, the RWST vent path will be free of ice blockage.

SR 3.5.4.3

The RWST water volume should be verified to be above the required minimum level of 89% (useable volume of > 395,000 gallons) in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.4

The boron concentration of the RWST should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA and will limit the power level increase and subsequently returns the reactor to subcritical immediately following an MSLB. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur, sufficient iodine will be retained to limit doses, stress corrosion cracking of equipment will be minimized, and hydrogen production will be minimized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. WCAP-13964, Revision 2, "Commonwealth Edison Company, Byron/Braidwood Units 1 & 2, Increased Steam Generator Tube Plugging/Reduced Thermal Design Flow/Positive Moderator Temperature Coefficient Analysis Program, Engineering/Licensing Report," September 1994.

2. UFSAR, Chapter 15.

3. UFSAR, Section 6.2.1.

This page intentionally left blank.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the centrifugal charging pump header to the Reactor Coolant System (RCS).

The restriction on Reactor Coolant Pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during Safety Injection (SI).

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break Loss Of Coolant Accident (LOCA) at full power (Ref. 1). The centrifugal charging pumps are also credited in the small break LOCA analysis. These two LOCA analyses establish the minimum flow for the ECCS pumps. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

BASES

APPLICABLE SAFETY ANALYSES (continued)

This LCO ensures that seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory. ITS Figure 3.5.5-1 was developed by using a conservative combination of plant data to establish a minimum flow loss coefficient for the seal injection line. Based on the conservative data, Figure 3.5.5-1 ensures adequate flow to the Reactor Coolant Pump seals while ensuring the safety analysis assumption for ECCS flow are maintained. Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 2).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is established by adjusting the RCP seal injection flow in the acceptable region of Figure 3.5.5-1 at a given pressure differential between the charging header and the RCS. The flow limits established by Figure 3.5.5-1 ensure that the minimum ECCS flow assumed in the safety analyses is maintained.

The limit on seal injection flow must be met to render the ECCS OPERABLE. If this condition is not met, the ECCS flow will not be as assumed in the accident analyses.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the unit shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4, where this LCO is no longer applicable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Verification that the manual seal injection throttle valves are adjusted to give a flow within the limit ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. To verify acceptable seal injection flow, the following is performed; differential pressure between the charging header (PT-120) and the RCS is determined and the seal injection flow is verified to be within the limits of Figure 3.5.5-1. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

REFERENCES

1. UFSAR, Chapter 6 and Chapter 15.

2. 10 CFR 50.46.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete containment building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis Loss Of Coolant Accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a shallow dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The cylinder wall is prestressed with a post tensioning system in the vertical and horizontal directions, and the dome roof is prestressed utilizing a three way post tensioning system.

The concrete containment building is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

BASES

BACKGROUND (continued)

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

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

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

   2. closed by manual valves, blind flanges, or de-activated automatic or remote manual valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. The equipment hatch is closed; and

d. The sealing mechanism associated with each penetration (e.g., welds, bellows, or O rings) is OPERABLE, except as provided in LCO 3.6.3.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA, secondary system pipe break, or fuel handling accident (Ref. 3). In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment leakage rate, used to evaluate doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.20% per day in the safety analysis at P_a = 42.8 psig for Unit 1 and P_a = 38.4 psig for Unit 2 (Ref. 3).

The radiological dose assessments performed for the design basis LOCA assume a maximum allowable containment leakage rate of 0.20% per day. In this case, the dose limits of 10 CFR 50.67 (Ref. 7) are not exceeded.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

BASES

LCO (continued)

Individual leakage rates specified for the containment air lock (LCO 3.6.2) and purge valves with resilient seals (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock and purge valve leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required leakage test is required to be < 0.6 L_a for combined Type B and C leakage and < 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Section XI, Subsection IWL of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR 50.55a, except where an alternative, exemption, or relief has been authorized by the NRC. Determining pre-stressing forces for inspections shall be consistent with the recommendations of Regulatory Guide 1.35.1, July 1990 (Ref. 6).

BASES

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. UFSAR, Chapter 15.
3. UFSAR, Section 6.2.
4. 10 CFR50.55a, "Codes and standards."
5. ASME Code, Section XI, Subsection IWL.
6. Regulatory Guide 1.35.1, July 1990.
7. 10 CFR 50.67.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 10 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the plant safety analyses.

BASES

APPLICABLE SAFETY ANALYSES

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a Loss of Coolant Accident (LOCA) and a steam line break. In addition, release of significant fission product radioactivity within containment can occur from a LOCA, secondary system pipe break, or fuel handling accident. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment leakage rate, used to evaluate doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.20% per day in the safety analysis at P_a = 42.8 psig for Unit 1 and P_a = 38.4 psig for Unit 2 (Ref. 2).

The radiological dose assessments performed for the design basis LOCA assume a maximum allowable containment leakage rate of 0.20% per day. In this case, the dose limits of 10 CFR 50.67 (Ref. 3) are not exceeded.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. If the inner door is inoperable, it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. Opening the OPERABLE door must be done under strict administrative controls, consisting of a dedicated individual (i.e., not involved with any repair or other maintenance effort) assigned to ensure that the door is opened only for the period of time required to gain entry into or exit from the air lock, and that any OPERABLE door is re-locked prior to the departure of the dedicated individual. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

BASES

ACTIONS (continued)

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

A.1, A.2, and A.3

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

Note that for the purpose of Required Actions A.1, A.2, and A.3, the bulkhead associated with an air lock door is considered to be part of the door. For example, an air lock door may be declared inoperable if the associated door shaft seal(s) are replaced or the equalizing device becomes inoperable, etc. It is appropriate to treat the associated bulkhead as part of the door because a leak path through the bulkhead is no different than a leak path past the door seals. The remaining OPERABLE door/bulkhead provides the necessary barrier between the containment atmosphere and the environs.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

BASES

ACTIONS (continued)

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions.

BASES

ACTIONS (continued)

Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls consist of a dedicated individual (i.e., not involved with any repair or other maintenance effort) assigned to ensure that the door is opened only for the period of time required to gain entry into or exit from the air lock, and that any OPERABLE door is re-locked prior to the departure of the dedicated individual. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A with the exception that both air lock doors may still be OPERABLE, in which case either door can be used to isolate the air lock penetration.

BASES

ACTIONS (continued)

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions.

Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock) and one door is re-locked prior to the departure of the dedicated individual.

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the doors, once they have been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B (e.g., both doors in the same air lock are inoperable) Condition C is entered. Note, an air lock with only an inoperable door (Condition A) and interlock (Condition B) does not require entry into Condition C. The Required Actions of Conditions A and B provide the appropriate remedial actions for the degraded condition. Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a unit shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time or in accordance with the Risk Informed Completion Time Program. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock and the overall containment leakage rate is within the Containment Leakage Rate Testing Program leakage limits.

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. UFSAR, Section 6.2.

3. 10 CFR 50.67.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves (Table B 3.6.3-1) form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic or remote manual valves secured in their closed position, check valves with flow through the valve secured, blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. These barriers (containment isolation valves, blind flanges, and closed systems) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a High-3 containment pressure signal and isolates the remaining process lines, except systems required for accident mitigation. The purge valves (supply and exhaust) receive a containment ventilation isolation signal on a containment high radiation condition, safety injection signal, manual Phase A actuation, and manual containment spray actuation. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

BASES

BACKGROUND (continued)

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

Normal Purge System (48 inch purge valves)

The Normal Purge System was originally designed to be used during shutdown conditions (i.e., MODES 5, 6, or defueled) to supply outside air into the containment for ventilation and cooling or heating and to reduce the concentration of noble gases within containment prior to and during personnel access. However, the Normal Purge System is not normally used. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 48 inch purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 48 inch purge valves are required to be maintained sealed closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained. The 48 inch purge valves are also normally maintained sealed closed during shutdown conditions (i.e., MODES 5, 6, or defueled) since the Normal Purge System is not normally used.

Minipurge System (8 inch purge valves)

The Minipurge System operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access; and

b. Equalize internal and external pressures.

Since the valves used in the Minipurge System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4.

The Minipurge System may also be used during shutdown conditions (i.e., MODES 5, 6, or defueled).

BASES

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

In MODES 1 through 4, the DBAs that result in a release of radioactive material within containment are a Loss Of Coolant Accident (LOCA), secondary system pipe break, and rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized. The safety analyses assume that the 48 inch purge valves are closed at event initiation.

In the calculation of control room and offsite doses following a LOCA, the accident analyses are performed in conformance with the requirements of Regulatory Guide 1.183 (Ref. 2).

The containment isolation valves ensure that the containment design leakage rate remains within L_a by automatically isolating penetrations that do not serve post accident functions and providing isolation capability for penetrations associated with safe shutdown functions. The maximum isolation time for automatic containment isolation valves is 60 seconds (Ref. 1). This isolation time is based on engineering judgement since the control room and offsite dose calculations are performed assuming that the leakage from containment begins immediately following the accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the containment mini purge valves. Two valves in series on each mini purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard isolation valves on each line are provided with diverse power sources and solenoid operated valves that will fail closed on the loss of power or air. This arrangement was designed to preclude common mode failures from disabling both valves on a mini purge line.

The normal purge valves may be unable to close in the environment following a LOCA. Therefore, each of the normal purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. The requirement to seal closed the normal purge valves precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves (Table B 3.6.3-1) form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic containment isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 48 inch purge valves must be maintained sealed closed. The valves covered by this LCO are listed along with their associated stroke times in Table B 3.6.3-1.

BASES

LCO (continued)

The normally closed containment isolation valves are considered OPERABLE when manual valves are closed or open under administrative controls, remote manual valves are closed, or automatic valves are de-activated and secured in their closed position. Other OPERABLE isolation devices include blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are those listed in Reference 1.

Purge valves with resilient seals must meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves (Table B 3.6.3-1) are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

BASES

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 48 inch purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event the containment isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

BASES

ACTIONS (continued)

A.1 and A.2

In the event one containment isolation valve (Table B 3.6.3-1) in one or more penetration flow paths is inoperable, except for purge valve leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic or remote manual containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. De-activated remote manual valves may include, air operated valves with air removed, or de-energized motor operated valves. Automatic valves refer to those valves that require a motive force to actuate, such as air or electric, and receive an automatic actuation signal. Power operated valves require a motive force to actuate, such as air or electric, but do not receive an automatic actuation signal. Based on the design, the acceptable means of isolating the 48 inch purge valve penetration is to close and de-activate the 48 inch purge valve. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours or in accordance with the Risk Informed Completion Time Program. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

BASES

ACTIONS (continued)

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days following isolation for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. However, penetration 94 for Containment Mini-Flow Purge Exhaust is an exception to the Condition A Note. Since only one inside valve and one outside valve are required to ensure isolation capability is maintained assuming a single failure, Condition A is applicable to this penetration flow path which contains three containment isolation valves, one inside valve (VQ005A) and two outside valves (VQ005B and VQ005C). If one or more outside valves are inoperable or the inside valve is inoperable in this penetration flow path, Required Actions A.1 and A.2 must be completed (Table B 3.6.3-2 Action 6.a and Action 6.b). For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

BASES

ACTIONS (continued)

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or otherwise securing components is to ensure these devices are not inadvertently mispositioned. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

BASES

ACTIONS (continued)

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, except for purge valve leakage not within limit, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic or remote manual valve, a closed manual valve, and a blind flange. De-activated remote manual valves may include, air operated valves with air removed, or de-energized motor operated valves. Automatic valves refer to those valves that require a motive force to actuate, such as air or electric, and receive an automatic actuation signal. Power operated valves require a motive force to actuate, such as air or electric, but do not receive an automatic actuation signal. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed once within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

BASES

ACTIONS (continued)

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path. However, penetration 94 for Containment Mini-Flow Purge Exhaust is an exception to the Condition B Note. Since only one inside valve and one outside valve are required to ensure isolation capability is maintained assuming a single failure, Condition B is applicable to this penetration flow path which contains three containment isolation valves, one inside valve (VQ005A) and two outside valves (VQ005B and VQ005C). If the inside valve and both outside valves in this penetration flow path are inoperable, Required Action B.1 must be completed (Table B 3.6.3-2 Action 6.d).

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic or remote manual valve, a closed manual valve, and a blind flange. De-activated remote manual valves may include, air operated valves with air removed, or de-energized motor operated valves. Automatic valves refer to those valves that require a motive force to actuate, such as air or electric, and receive an automatic actuation signal. Power operated valves require a motive force to actuate, such as air or electric, but do not receive an automatic actuation signal. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time or in accordance with the Risk Informed Completion Time Program. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days following isolation for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

BASES

ACTIONS (continued)

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Reference 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system. Condition C is applicable to the penetration flow paths associated with Penetrations 92 and 93 containing the Containment Sump Isolation Valves. Although the flow path containing the Containment Sump Isolation Valve connects to an open system inside containment, this flow path connects to the Containment Spray and Emergency Core Cooling Systems outside containment. These systems are closed systems outside containment and serve as the second containment isolation barrier.

Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or otherwise securing components is to ensure these devices are not inadvertently mispositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

<u>D.1</u>

In the event one or more containment purge valves in one or more penetration flow paths are not within the purge valve leakage limits, purge valve leakage must be restored to within limits within 24 hours. If the leakage results in exceeding the overall containment leakage rate acceptance criteria, ACTIONS Note 4 would assure the more restrictive ACTIONS of LCO 3.6.1, "Containment," are applied. The specified Completion Time of 24 hours represents a reasonable time to effect repairs of leaking purge valve(s).

BASES

ACTIONS (continued)

E.1 and E.2

If the Required Actions and associated Completion Times are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 48 inch containment purge valve is required to be verified sealed closed. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by installing a mechanical block. In this application, the term "sealed" has no connotation of leak tightness. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2

This SR ensures that the minipurge valves are closed as required or, if open, open for an allowable reason under administrative control. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the minipurge valves are open under administrative control. The valves may be opened for example; for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The minipurge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve, remote manual valve, and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve, remote manual valve, and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The 48 inch purge valves are not qualified for automatic closure from their open position under DBA conditions due to their large size and are, thus, maintained sealed closed in MODES 1, 2, 3, and 4. The safety analyses assume that the 48 inch purge valves are closed at event initiation. The isolation time and Frequency of this SR are in accordance with the INSERVICE TESTING PROGRAM.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6 and SR 3.6.3.7

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B, is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.8

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Section 6.2.
2. Regulatory Guide 1.183, July 2000.
3. Standard Review Plan 6.2.4.

Table B 3.6.3-1 (page 1 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
76	1AF013D[(a)]		1AF013D S/G D Isol Vlv	N/A	3
99	2AF013D[(a)]		2AF013D S/G D Isol Vlv	N/A	3
76	1AF013H[(a)]		1AF013H S/G D Isol Vlv	N/A	3
99	2AF013H[(a)]		2AF013H S/G D Isol Vlv	N/A	3
79	1AF013A[(a)]		1AF013A S/G A Isol Vlv	N/A	3
100	2AF013A[(a)]		2AF013A S/G A Isol Vlv	N/A	3
79	1AF013E[(a)]		1AF013E S/G A Isol Vlv	N/A	3
100	2AF013E[(a)]		2AF013E S/G A Isol Vlv	N/A	3
84	1AF013B[(a)]		1AF013B S/G B Isol Vlv	N/A	3
101	2AF013B[(a)]		2AF013B S/G B Isol Vlv	N/A	3
84	1AF013F[(a)]		1AF013F S/G B Isol Vlv	N/A	3
101	2AF013F[(a)]		2AF013F S/G B Isol Vlv	N/A	3
87	1AF013C[(a)]		1AF013C S/G C Isol Vlv	N/A	3
102	2AF013C[(a)]		2AF013C S/G C Isol Vlv	N/A	3
87	1AF013G[(a)]		1AF013G S/G C Isol Vlv	N/A	3
102	2AF013G[(a)]		2AF013G S/G C Isol Vlv	N/A	3
76	1AF049D[(a)]		1AF049D FX S/G 1D Isol Check Vlv	N/A	3
79	1AF049A[(a)]		1AF049A FX S/G 1A Isol Check Vlv	N/A	3
84	1AF049B[(a)]		1AF049B FX S/G 1B Isol Check Vlv	N/A	3
87	1AF049C[(a)]		1AF049C FX S/G 1C Isol Check Vlv	N/A	3
99	2AF049D[(a)]		2AF049D FX S/G 2D Isol Check Vlv	N/A	3
100	2AF049A[(a)]		2AF049A FX S/G 2A Isol Check Vlv	N/A	3
101	2AF049B[(a)]		2AF049B FX S/G 2B Isol Check Vlv	N/A	3
102	2AF049C[(a)]		2AF049C FX S/G 2C Isol Check Vlv	N/A	3
21	CC9414	CC9416 CC9534	CC9414 CC From RC Pumps Isol Vlv CC9416 CC From RC Pumps Isol Vlv CC9534 CC From RC Pmp Isol Byp Check Vlv	10.0 10.0 N/A	1
22	CC9437B[(a)]		CC9437B CC From Exc Ltdwn Hx Isol Vlv	10.0	3
24	CC685	CC9438 CC9518	CC685 CC From RC Pps Therm Bar Isol Vlv CC9438 CC From RC Pps Therm Bar Isol Vlv CC9518 CC Frm RC Pps Therm Barr Iso Byp Chk	10.0 10.0 N/A	1

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 2 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
25	CC9413A	CC9486	CC9413A CC9486	CC To RC Pumps Isol Vlv CC Rx Support Cool Sup Hdr Chk Vlv	10.0 N/A	2
18	CC9437A[(a)]		CC9437A	CC To Exc Ltdwn Hx Isol Vlv	10.0	3
1	CS007A[(a)]	CS008A[(a)]	CS007A CS008A	Cnmt Spray Pp A Hdr Isol Vlv Cnmt Spray Hdr A Inbd Cnmt Check	30.0 N/A	2
16	CS007B[(a)]	CS008B[(a)]	CS007B CS008B	Cnmt Spray Pp B Hdr Isol Vlv Cnmt Spray Hdr B Inbd Cnmt Check	30.0 N/A	2
28	CV8100[(a)]	CV8112[(a)] CV8113[(a)]	CV8100 CV8112 CV8113	Seal Wtr Rtrn Cnmt Isol Vlv Seal Wtr Rtrn Cnmt Isol Vlv Seal Wtr Rtrn Check Vlv	10.0 10.0 N/A	1
33	CV8355A[(a)]	CV8368A[(a)]	CV8355A CV8368A	RCP Seal Injection Isol RCP Seal Injection Cnmt Isol Vlv	N/A N/A	2
33	CV8355D[(a)]	CV8368D[(a)]	CV8355D CV8368D	RCP Seal Injection Isol RCP Seal Injection Cnmt Isol Vlv	N/A N/A	2
37	CV8346[(a)]	CV8348[(a)]	CV8346 CV8348	Loop Fill Hdr Outbd Man Isol Vlv RC Loop Fill Cnmt Isol Vlv	N/A N/A	2
41	CV8152[(a)]	CV8160[(a)]	CV8152 CV8160	Letdown Line Cnmt Isol Vlv Letdown Line Cnmt Isol Vlv	10 10	2
53	CV8355B[(a)]	CV8368B[(a)]	CV8355B CV8368B	RCP Seal Injection RCP Seal Injection Cnmt Isol Vlv	N/A N/A	2
53	CV8355C[(a)]	CV8368C[(a)]	CV8355C CV8368C	RCP Seal Injection RCP Seal Injection Cnmt Isol Vlv	N/A N/A	2
71	CV8105[(a)] CV8106[(a)]		CV8105 CV8106	Chg Line Cnmt Isol Vlv Chg Line Cnmt Isol Vlv	10 10	10
32	FC011	FC012	FC011 FC012	Dem Loop Rtn To Rfuel Cav Cnmt Isol Dem Loop Rtn To Rfuel Cav Cnmt Isol	N/A N/A	2
57	FC010	FC009	FC010 FC009	Pp Suct From Refuel Cav Cnmt Isol Pp Suct From Refuel Cav Cnmt Isol	N/A N/A	2
34	FP010[(a)]	FP345[(a)]	FP010 FP345	Fire Protection O/S Isol 364 Vlv Fire Prot Cnmt Isol Vlv	12.0 N/A	2

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 3 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
76	FW009D[a]		FW009D FW Isolation Vlv Loop D	5.0	3
	2FW043D[a]		2FW043D S/G D FWIV Bypass Isol Vlv	6.0	
79	FW009A[a]		FW009A FW Isolation Vlv Loop A	5.0	3
	2FW043A[a]		2FW043A S/G A FWIV Bypass Isol Vlv	6.0	
84	FW009B[a]		FW009B FW Isolation Vlv Loop B	5.0	3
	2FW043B[a]		2FW043B S/G B FWIV Bypass Isol Vlv	6.0	
87	FW009C[a]		FW009C FW Isolation Vlv Loop C	5.0	3
	2FW043C[a]		2FW043C S/G C FWIV Bypass Isol Vlv	6.0	
76	1FW035D[a]		1FW035D S/G D FW Temprng Isol Vlv	6.0	3
76	1FW039D[a]		1FW039D S/G 1D Low Flow FW Isol Vlv	6.0	
99	1FW015D[a]		1FW015D 1D SG Chem Feed Isol	N/A	
99	2FW035D[a]		2FW035D S/G D FW Temprng Isol Vlv	6.0	3
	2FW039D[a]		2FW039D S/G D FW Phtr Byp Vlv 377 DWST Isol	6.0	
	2FW015D[a]		2FW015D SG D FW Chem Feed Isol	N/A	
79	1FW035A[a]		1FW035A S/G A FW Temprng Isol Vlv	6.0	3
79	1FW039A[a]		1FW039A S/G 1A Low Flow FW Isol Vlv	6.0	
100	1FW015A[a]		1FW015A 1A SG Chem Feed Isol	N/A	
100	2FW035A[a]		2FW035A S/G A FW Temprng Isol Vlv	6.0	3
	2FW039A[a]		2FW039A S/G A FW Phtr Byp Vlv 377 DWST Isol	6.0	
	2FW015A[a]		2FW015A SG A FW Chem Feed Isol	N/A	
84	1FW035B[a]		1FW035B S/G B FW Temprng Isol Vlv	6.0	3
84	1FW039B[a]		1FW039B S/G 1B Low Flow FW Isol Vlv	6.0	
101	1FW015B[a]		1FW015B 1B SG Chem Feed Isol	N/A	
101	2FW035B[a]		2FW035B S/G B FW Temprng Isol Vlv	6.0	3
	2FW039B[a]		2FW039B S/G B FW Phtr Byp Vlv 377 DWST Isol	6.0	
	2FW015B[a]		2FW015B SG B FW Chem Feed Isol	N/A	
87	1FW035C[a]		1FW035C S/G C FW Temprng Isol Vlv	6.0	3
87	1FW039C[a]		1FW039C S/G 1C Low Flow FW Isol Vlv	6.0	
102	1FW015C[a]		1FW015C 1C SG Chem Feed Isol	N/A	
102	2FW035C[a]		2FW035C S/G C FW Temprng Isol Vlv	6.0	3
	2FW039C[a]		2FW039C S/G C FW Phtr Byp Vlv 377 DWST Isol	6.0	
	2FW015C[a]		2FW015C SG C FW Chem Feed Isol	N/A	

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 4 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
39	IA065	IA066	IA065	O/S Cnmt Isol Vlv Isol Vlv	15.0	1
		IA091	IA066	Instrument Air Inside Isol Vlv	15.0	
			IA091	Upstrm IA Sply To AOV-IA066 Chk Vlv	N/A	
77	MS101D[a]		MS101D	MSIV Bypass Vlv Loop D	6.0	3
	MS013D[a]		MS013D	SG D 1235 Psig Relief	N/A	
	MS014D[a]		MS014D	SG D 1220 Psig Relief	N/A	
	MS015D[a]		MS015D	SG D 1205 Psig Relief	N/A	
	MS016D[a]		MS016D	SG D 1190 Psig Relief	N/A	
	MS017D[a]		MS017D	SG D 1175 Psig Relief	N/A	
	MS018D[a]		MS018D	SG D PORV	20.0	
	MS021D[a]		MS021D	SG D Dripleg Drn DWST Isol	N/A	
78	MS101A[a]		MS101A	MSIV Bypass Vlv Loop A	6.0	3
	MS013A[a]		MS013A	SG A 1235 Psig Relief	N/A	
	MS014A[a]		MS014A	SG A 1220 Psig Relief	N/A	
	MS015A[a]		MS015A	SG A 1205 Psig Relief	N/A	
	MS016A[a]		MS016A	SG A 1190 Psig Relief	N/A	
	MS017A[a]		MS017A	SG A 1175 Psig Relief	N/A	
	MS018A[a]		MS018A	SG A PORV	20.0	
	MS021A[a]		MS021A	SG A Dripleg Drn DWST Isol	N/A	
85	MS101B[a]		MS101B	MSIV Bypass Vlv Loop B	6.0	3
	MS013B[a]		MS013B	SG B 1235 Psig Relief	N/A	
	MS014B[a]		MS014B	SG B 1220 Psig Relief	N/A	
	MS015B[a]		MS015B	SG B 1205 Psig Relief	N/A	
	MS016B[a]		MS016B	SG B 1190 Psig Relief	N/A	
	MS017B[a]		MS017B	SG B 1175 Psig Relief	N/A	
	MS018B[a]		MS018B	SG B PORV	20.0	
	MS021B[a]		MS021B	SG B Dripleg Drn DWST Isol	N/A	
86	MS101C[a]		MS101C	MSIV Bypass Vlv Loop C	6.0	3
	MS013C[a]		MS013C	SG C 1235 Psig Relief	N/A	
	MS014C[a]		MS014C	SG C 1220 Psig Relief	N/A	
	MS015C[a]		MS015C	SG C 1205 Psig Relief	N/A	
	MS016C[a]		MS016C	SG C 1190 Psig Relief	N/A	
	MS017C[a]		MS017C	SG C 1175 Psig Relief	N/A	
	MS018C[a]		MS018C	SG C PORV	20.0	
	MS021C[a]		MS021C	SG C Dripleg Drn DWST Isol	N/A	
13	OG082	OG079	OG082	H2 Recomb Outbd Cnmt Isol Vlv	60.0	2
			OG079	H2 Recomb Disch Cnmt Isol Vlv	60.0	
13	OG084	OG080	OG084	H2 Recomb Outbd Cnmt Isol Vlv	60.0	2
			OG080	H2 Recomb Suct Cnmt Isol Vlv	60.0	
23	OG085	OG081	OG085	H2 Recomb Outbd Cnmt Isol Vlv	60.0	2
			OG081	H2 Recomb Suction Cnmt Isol Vlv	60.0	
69	OG083	OG057A	OG083	H2 Recomb Outbd Cnmt Isol Vlv	60.0	2
			OG057A	H2 Recomb Cnmt Isol Vlv	60.0	

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 5 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
52	PR001A PR001B		PR001A PR001B	UPST Cnmt Atmos To PR O/S Isol Vlv DWST Cnmt Atmos To PR O/S Isol Vlv	4.5 4.5	10
52	PR066	PR032	PR066 PR032	Sample Return O/S Cnmt Isol Cnmt Process Rad Mon Return Chk	5.0 N/A	2
36	PS228B PS229B		PS228B PS229B	Post LOCA H2 Mon B Cnmt Isol Vlv Post LOCA H2 Mon B Cnmt Isol Vlv	N/A(b) N/A(b)	10
36	PS230B	PS231B	PS230B PS231B	Post LOCA H2 Mon B Cnmt Isol Vlv Post LOCA H2 Mon B Return Chk Vlv	N/A(b) N/A	2
45	PS228A PS229A		PS228A PS229A	Post LOCA H2 Mon A Cnmt Isol Vlv Post LOCA H2 Mon A Cnmt Isol Vlv	N/A(b) N/A(b)	10
45	PS230A	PS231A	PS230A PS231A	Post LOCA H2 Mon A Cnmt Isol Vlv Post LOCA H2 Mon A Return Chk Vlv	N/A(b) N/A	2
70	PS9354B	PS9354A	PS9354B PS9354A	Pzr Stm Sample Cnmt Isol Vlv Pzr Stm Sample Cnmt Isol Vlv	10.0 10.0	2
70	PS9355B	PS9355A	PS9355B PS9355A	Pzr Lqd Sample Cnmt Isol Vlv Pzr Lqd Sample Cnmt Isol Vlv	10.0 10.0	2
70	PS9356B	PS9356A	PS9356B PS9356A	Loop Sample Cnmt Isol Vlv Loop Sample Cnmt Isol Vlv	10.0 10.0	2
70	PS9357B	PS9357A	PS9357B PS9357A	Accumulator Sample Cnmt Isol Vlv Accumulator Sample Cnmt Isol Vlv	10.0 10.0	2
11	RE9170	RE1003 RE022	RE9170 RE1003 RE022	RCDT Pumps Outside Isol Vlv RCDT Pumps Dsch Cnmt Inbd Isol Vlv RCDT Pumps Dsch Relief Vlv	10.0 10.0 N/A	1

(continued)

(b) Proper valve operation will be demonstrated by verifying that the valve strokes to its required position.

Table B 3.6.3-1 (page 6 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
65	RE9157 RE9160B	RE9160A	RE9157 RE9160B RE9160A	RCDT N2 Supply Outside Isol Vlv RCDT Vent Outside Isol Vlv RCDT Vent A N2 Sup Inside Isol Vlv	10.0 10.0 10.0	4
65	RE9159B	RE9159A	RE9159B RE9159A	RCDT To Gas Anal Outside Isol Vlv RCDT To Gas Anal Inside Isol Vlv	10.0 10.0	2
47	RF027	RF026 RF055	RF027 RF026 RF055	Cnmt Flr Drn Sump Dsch Hdr O/S Isol Cnmt Flr Drn Sump Dsch Hdr I/S Isol Cnmt Flr Drn Sump Dsch Hdr Relief Vlv	15.0 15.0 N/A	1
68		RH8701A[a] RH8701B[a]	RH8701A RH8701B	RC Loop A To RH PP A Suct 377 Isol RC Loop A To RH PP A Suct 377 Isol	N/A N/A	9
75		RH8702A[a] RH8702B[a]	RH8702A RH8702B	RC Loop C To RH PP B Suct 377 Isol RC Loop C To RH PP B Suct 377 Isol	N/A N/A	9
I5	RY075		RY075	O/S CTMT Dead Weight Tester Isol	N/A	3
27	RY8025	RY8026	RY8025 RY8026	PRT To Gas Anal Cnmt Isol Vlv PRT To Gas Anal Cnmt Isol Vlv	10.0 10.0	2
27	RY8033	RY8047	RY8033 RY8047	N2 Supply To PRT Isol Vlv PRT N2 Supply Line I/S Cnmt Chk Vlv	10.0 N/A	2
44	RY8028	RY8046	RY8028 RY8046	PW To PRT Cnmt Isol Vlv PRT Spray Line Inside Cnmt Chk Vlv	10.0 N/A	2
56	SA032	SA033	SA032 SA033	Service Air Cnmt Isol Vlv O/S Service Air Inside Isol Vlv	4.5 4.5	2
80/81/99	1SD002C[a] 1SD002D[a] 1SD005B[a]		1SD002C 1SD002D 1SD005B	S/G 1D B/D Isol S/G 1D B/D Isol S/G 1D B/D Sample Isol	7.5 7.5 3.0	3
80/81	2SD002C[a] 2SD002D[a] 2SD005B[a]		2SD002C 2SD002D 2SD005B	S/G 2D Upper B/D Isol S/G 2D Lower B/D Isol S/G 2D B/D Sample Isol	7.5 7.5 3.0	3
82/83/100	1SD002A[a] 1SD002B[a] 1SD005A[a]		1SD002A 1SD002B 1SD005A	S/G 1A B/D Isol S/G 1A B/D Isol S/G 1A B/D Sample Isol	7.5 7.5 3.0	3
82/83	2SD002A[a] 2SD002B[a] 2SD005A[a]		2SD002A 2SD002B 2SD005A	S/G 2A Upper B/D Isol S/G 2A Lower B/D Isol S/G 2A B/D Sample Isol	7.5 7.5 3.0	3

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 7 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION	MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
88/89/101	1SD002E[a]		1SD002E S/G 1B B/D Isol	7.5	3
	1SD002F[a]		1SD002F S/G 1B B/D Isol	7.5	
	1SD005C[a]		1SD005C S/G 1B B/D Sample Isol	3.0	
88/89	2SD002E[a]		2SD002E S/G 2B Upper B/D Isol	7.5	3
	2SD002F[a]		2SD002F S/G 2B Lower B/D Isol	7.5	
	2SD005C[a]		2SD005C S/G 2B B/D Sample Isol	3.0	
90/91/102	1SD002G[a]		1SD002G S/G 1C B/D Isol	7.5	3
	1SD002H[a]		1SD002H S/G 1C B/D Isol	7.5	
	1SD005D[a]		1SD005D S/G 1C B/D Sample Isol	3.0	
90/91	2SD002G[a]		2SD002G S/G 2C Upper B/D Isol	7.5	3
	2SD002H[a]		2SD002H S/G 2C Lower B/D Isol	7.5	
	2SD005D[a]		2SD005D S/G 2C B/D Sample Isol	3.0	
26	SI8801A[a]	SI8815[a]	SI8801A CHG Pp To Cold Legs Inj Isol	N/A	5
	SI8801B[a]	SI8843[a]	SI8801B CHG Pp To Cold Legs Isol Vlv	N/A	
			SI8815 Chg Pps Cold Leg Inj Hdr Chk Vlv	N/A	
			SI8843 Accum Fill Frm SI Tst Line Isol Vlv	N/A	
50	SI8809A[a]	SI8890A[a]	SI8809A RH To Cold Legs A/D Isol Vlv	N/A	7
		SI8818A[a]	SI8890A RHR To Cold Legs 1&4 Tst Line Iso Vl	N/A	
		SI8818D[a]	SI8818A SI Loop 1 Cold Leg Upst Chk Vlv	N/A	
			SI8818D SI Loop 4 Cold Leg Upst Chk Vlv	N/A	
51	SI8809B[a]	SI8890B[a]	SI8809B RH To Cold Legs B/C Isol Vlv	N/A	7
		SI8818B[a]	SI8890B RHR To Cold Legs 2&3 Tst Line Iso Vl	N/A	
		SI8818C[a]	SI8818B SI Loop 2 Cold Leg Upst Chk Vlv	N/A	
			SI8818C SI Loop 3 Cold Leg Upst Chk Vlv	N/A	
55	SI8964	SI8871	SI8964 SI Test Lines To Radwaste Isol Vlv	10.0	4
	SI8888		SI8888 SI Pps To Accum Fill Line Isol Vlv	10.0	
			SI8871 Fill/Test Line Isol Vlv	10.0	
55	SI8880	SI8968	SI8880 SI Accumulators N2 Supply Isol Vlv	10.0	2
			SI8968 SI Accum N2 Supply Chk Vlv	N/A	
59	SI8802A[a]	SI8881[a]	SI8802A SI To Hot Legs A/D Isol Vlv	N/A	7
		SI8905A[a]	SI8881 SI Test Line Iso Vlv, SI Pps To A/D Hot Legs	N/A	
		SI8905D[a]	SI8905A SI Loop 1 Hot Leg Upst Chk Vlv		
			SI8905D SI Loop 4 Hot Leg Upst Chk Vlv	N/A	
				N/A	
60	SI8835[a]	SI8823[a]	SI8835 SI Pps Cold Legs Isol Vlv	N/A	7
		SI8819A[a]	SI8823 SI Test Line Iso Vlv, SI Pps To Cold Legs	N/A	
		SI8819B[a]	SI8819A SI Pps Dsch Hdr To Cold Leg Lp 1 Chk	N/A	
		SI8819C[a]	SI8819B SI Pps Dsch Hdr To Cold Leg Lp 2 Chk	N/A	
		SI8819D[a]	SI8819C SI Pps Dsch Hdr To Cold Leg Lp 3 Chk	N/A	
			SI8819D SI Pps Dsch Hdr To Cold Leg Lp 4 Chk	N/A	

(continued)

(a) Not subject to Type C leakage tests.

Table B 3.6.3-1 (page 8 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
66	SI8840[(a)]	SI8825[(a)] SI8841A[(a)] SI8841B[(a)]	SI8840 SI8825 SI8841A SI8841B	RH To Hot Legs A/D Isol Vlv RHR To Cold Legs 1&3 Tst Line Iso Vl SI Loop 1 Hot Leg Upst Chk Vlv SI Loop 3 Hot Leg Upst Chk Vlv	N/A N/A N/A N/A	7
73	SI8802B[(a)]	SI8824[(a)] SI8905B[(a)] SI8905C[(a)]	SI8802B SI8824 SI8905B SI8905C	SI To Hot Legs B/C Isol Vlv SI Test Line Iso Vlv, SI Pps To B/C Hot Legs SI Loop 2 Hot Leg Upst Chk Vlv SI Loop 3 Hot Leg Upst Chk Vlv	N/A N/A N/A N/A	7
92	SI8811A[(a)]		SI8811A	Cnmt Sump A Isol Vlv	N/A	3
93	SI8811B[(a)]		SI8811B	Cnmt Sump B Isol Vlv	N/A	3
7	SX016B[(a)]		SX016B	Rx Cnmt Fan Cooler B/D SX Inlet	N/A	3
9	SX027B[(a)]		SX027B	Rx Cnmt Fan Cooler B/D SX Outlet	N/A	3
14	SX027A[(a)]		SX027A	Rx Cnmt Fan Cooler A/C SX Outlet	N/A	3
15	SX016A[(a)]		SX016A	Rx Cnmt Fan Cooler A/C SX Inlet	N/A	3
I3	VQ018	VQ016	VQ018 VQ016	Int Leak Rate Cnmt Isol Int Leak Rate Cnmt Isol	N/A N/A	2
I3	VQ019	VQ017	VQ019 VQ017	Int Leak Rate Cnmt Isol Int Leak Rate Cnmt Isol	N/A N/A	2
94	VQ003 VQ005C VQ005B	VQ005A	VQ003 VQ005C VQ005B VQ005A	Cnmt Post-LOCA Purge Isol Cnmt Mini-Flow Purge Exhaust Isol Cnmt Mini-Flow Purge Exhaust Isol Cnmt Mini-Flow Purge Exhaust Isol	5.0 5.0 5.0 5.0	6[(c)]
95	VQ002B	VQ002A	VQ002B VQ002A	Cnmt Purge Exhaust Isol Vlv Cnmt Purge Exhaust Isol Vlv	N/A[(d)] N/A[(d)]	2[(c)]
96	VQ004B	VQ004A	VQ004B VQ004A	Cnmt Mini-Flow Purge Supply Isol Cnmt Mini-Flow Purge Supply Isol	5.0 5.0	2[(c)]
97	VQ001B	VQ001A	VQ001B VQ001A	Cnmt Purge Supply Isol Vlv Cnmt Purge Supply Isol Vlv	N/A[(d)] N/A[(d)]	2[(c)]
30	WM190	WM191	WM190 WM191	Demin Wtr Hdr To Cnmt DWST Isol Demin Wtr Hdr To Cnmt Check Vlv	N/A N/A	2

(continued)

(a) Not subject to Type C leakage tests.
(c) Valve INOPERABLE as a result of leakage not within limit, refer to Tech Spec 3.6.3, Condition D.
(d) The Normal Purge System 48 inch valves are not qualified for automatic closure from their open position under DBA conditions and are, thus, maintained sealed closed in MODES 1, 2, 3, and 4.

Table B 3.6.3-1 (page 9 of 9)
Primary Containment Isolation Valves

PENETRATION NUMBER	OUTSIDE VALVE	INSIDE VALVE	FUNCTION		MAXIMUM ISOLATION TIME (SEC)	Table B 3.6.3-2 ACTION
5	WO020A	WO056A	WO020A	Rx Cnmt Fn Coolers A/C Chl Wtr Out	50.0	1
		WO079A	WO056A	Rx Cnmt Fn Coolers A/C Chl Wtr Out	50.0	
			WO079A	Rx Cnmt Fn Coolers A/C Chl Wtr Out Rlf Vlv	N/A	
6	WO006A	WO007A	WO006A	Rx Cnmt Fn Coolers A/C Chl Wtr In	50.0	2
			WO007A	A/C RCFC Supply Hdr Incnmt Check	N/A	
8	WO020B	WO056B	WO020B	Rx Cnmt Fn Coolers B/D Chl Wtr Out	50.0	1
		WO079B	WO056B	Rx Cnmt Fn Coolers B/D Chl Wtr Out	50.0	
			WO079B	Rx Cnmt Fn Coolers B/D Chl Wtr Out Rlf Vlv	N/A	
10	WO006B	WO007B	WO006B	Rx Cnmt Fn Coolers B/D Chl Wtr In	50.0	2
			WO007B	B/D RCFC Supply Hdr Incnmt Check	N/A	

Table B 3.6.3-2 (page 1 of 1)
Primary Containment Isolation Valves

ACTION NUMBER		STATUS OF AFFECTED CONTAINMENT ISOLATION VALVE(S)	APPLICABLE LCO 3.6.3 CONDITION
1	a.	Outside valve OR either inside valve INOPERABLE	A
	b.	Both inside valves INOPERABLE	A
	c.	Outside AND either inside valve INOPERABLE	B
2	a.	Outside valve OR inside valve INOPERABLE	A
	b.	Outside valve AND inside valve INOPERABLE	B
3	a.	Valve INOPERABLE	C
4	a.	Inside valve OR either outside valve INOPERABLE	A
	b.	Both outside valves INOPERABLE	A
	c.	Inside valve AND either outside valve INOPERABLE	B
5	a.	Either of the outside valves OR either of the inside valves INOPERABLE	A
	b.	Both inside valves OR both outside valves INOPERABLE	A
	c.	Either of the inside valves AND either of the outside valves INOPERABLE	B
6	a.	1 OR more outside valves INOPERABLE	A
	b.	Inside valve INOPERABLE	A
	c.	Inside valve AND VQ003 INOPERABLE	B
	d.	Inside valve AND both VQ005B and VQ005C INOPERABLE	B
7	a.	1 OR more inside valves INOPERABLE	A
	b.	Outside valve INOPERABLE	A
	c.	Outside valve AND any inside valve(s) INOPERABLE	B
8	Not Used		N/A
9	a.	1 inside valve INOPERABLE	A
	b.	Both inside valves INOPERABLE	B
10	a.	1 outside valve INOPERABLE	A
	b.	Both outside valves INOPERABLE	B

This page intentionally left blank.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Loss Of Coolant Accident (LOCA) or Steam Line Break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer modeled pressure transients. The worst case LOCA generates larger mass and energy release than the worst case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The initial pressure condition used in the containment analysis was 1.0 psig. This resulted in a maximum peak pressure from a LOCA of 42.8 psig for Unit 1 and 38.4 psig for Unit 2. The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure, P_a, results from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA does not exceed the containment design pressure, 50 psig.

The containment was also evaluated for an external pressure load equivalent to -3.5 psig (Ref. 2). The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure. The initial pressure condition used in this analysis was 0.0 psig. This resulted in a minimum pressure inside containment of -3.48 psig, which is less than the design load.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 3).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit provides reasonable assurance that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3, and 4. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODES 5 or 6.
ACTIONS	<u>A.1</u> When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.2.
2. Safety Evaluation Report Related to the Operation of Byron Station Units 1 and 2, Supplement 2.
3. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Loss of Coolant Accident (LOCA) or Steam Line Break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling Systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses and is an important consideration in establishing the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) Systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F. This resulted in a maximum containment air temperature of 333.6°F for Unit 1 and 330.8°F for Unit 2. The design temperature of the containment structure is 280°F. The maximum peak containment air temperature was calculated to exceed the containment design temperature for only a few seconds during the transient. Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the containment temperatures remained below the design temperature. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The containment average air temperature limit is also used to establish the environmental qualification operating envelope for containment. The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a LOCA. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the evaluated containment temperatures. As a result, the ability of containment to perform its design function is ensured.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODES 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

BASES

ACTIONS (continued)

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a conservative estimate of the overall containment atmosphere (e.g., the dry bulb inlet temperature of the running reactor containment fan coolers). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.2.

2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling Systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine and aerosol removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Cooling Systems are designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," GDC 40, "Testing of Containment Heat Removal Systems," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup Systems," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems" (Ref. 1).

The Containment Cooling System and Containment Spray System are Engineered Safety Feature (ESF) Systems and are discussed in UFSAR, Sections 9.4.8 and 6.5.2, respectively (Refs. 2 and 3). They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System in conjunction with the Containment Cooling System limit and maintain post accident conditions to less than the containment design values. In addition, the Containment Spray System and Containment Cooling System provide a method of ensuring a mixed atmosphere during post Loss of Coolant Accident (LOCA) conditions and satisfy the requirements of 10 CFR 50.44(b)(1).

BACKGROUND (continued)

Containment Spray System

The Containment Spray System consists of two separate 100% capacity trains, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The Refueling Water Storage Tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment sump(s).

The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the residual heat removal heat exchangers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of $\geq$ 8.0 for the containment sump water ensures that radioiodines removed from the containment atmosphere by spray or natural deposition will remain in solution and not re-evolve from water in the containment sump. The upper pH limit minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid. The chemical aspects of iodine removal capability are addressed in LCO 3.6.7, "Spray Additive System."

BASES

BACKGROUND (continued)

The Containment Spray System is actuated either automatically by a containment High-3 pressure signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. The injection phase continues until an RWST LO-3 alarm is received, and the operator manually aligns the system to the recirculation mode. The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 100% of the design cooling requirement, are provided. Each train consisting of two Reactor Containment Fan Coolers (RCFCs) is supplied with cooling water from a separate train of Essential Service Water (SX) and is powered from a separate ESF bus. During all operating conditions, air is drawn from the upper volume of the containment approximately 50 feet above the operating floor by a return air riser (one riser for each RCFC unit). The return air is then routed through the SX cooling coils, the Chilled Water (WO) cooling coils, and the fan and discharge duct (one for each RCFC unit). The RCFC discharges directly into the lower containment volume. The WO chiller unit condensers are served by the SX return from the RCFC SX cooling coils. Upon receipt of an ESF signal, the WO condensers are automatically isolated from SX.

Containment Cooling System train A consists of RCFC A and C; and train B consists of RCFC B and D.

BASES

BACKGROUND (continued)

During normal operation, the fans are operated at high speed with SX supplied to the cooling coils. The Containment Cooling System is designed to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent adverse fan conditions (e.g., motor overload, increased blade stresses) from the higher mass atmosphere. The temperature of the SX is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the LOCA and the Steam Line Break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 42.8 psig for Unit 1 and 38.4 psig for Unit 2 (experienced during a LOCA). The analysis shows that the peak containment temperature is 333.6°F for Unit 1 and 330.8°F for Unit 2 (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level of 3672.6 MWt, one containment spray train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 1.0 psig. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 4).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in a -3.48 psig containment pressure and is associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4.

The modeled Containment Spray System actuation from the LOCA containment analysis is based on a response time associated with exceeding the containment High-3 pressure setpoint to achieving full flow through the containment spray nozzles. The Containment Spray System total response time of 110.2 seconds (for the limiting case) includes Diesel Generator (DG) startup (for loss of offsite power), sequencing of equipment, containment spray pump startup, and spray line filling (Ref. 5).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment cooling train performance for post accident conditions is given in Reference 6. The result of the analysis is that each train can provide 100% of the required peak cooling capacity during the post accident condition. The train post accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 7.

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-3 pressure setpoint to achieving full Containment Cooling System air and safety grade cooling water flow. The Containment Cooling System total response time of 65 seconds, includes signal delay, DG startup (for loss of offsite power), and service water pump startup times (Ref. 5).

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, a minimum of one containment cooling train and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 7). Additionally, one containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and two containment cooling trains must be OPERABLE. The chemical aspects of iodine removal capability are addressed in LCO 3.6.7. Therefore, in the event of an accident, at least one train in each system operates, assuming the worst case single active failure occurs.

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and manually transferring suction to the containment sump. Management of gas voids is important to Containment Spray System OPERABILITY.

BASES

LCO (continued)

Each Containment Cooling System includes cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and the Containment Cooling System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 7 day Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one or more of the containment cooling trains inoperable, the inoperable containment cooling train(s) must be restored to OPERABLE status within 7 days. The OPERABLE components in this degraded condition provide iodine removal capabilities and provide a redundant cooling system for heat removal needs. The 7 day Completion Time was developed taking into account the heat removal capabilities afforded by the Containment Spray System and the low probability of DBA occurring during this period.

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Action and associated Completion Time of Condition C of this LCO are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

E.1

With two containment spray trains or any combination of three or more containment spray and cooling trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance is modified by a Note which exempts system vent flow paths opened under administrative control. The administrative control should be proceduralized and 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.2

Operating each containment cooling train fan unit (in slow speed) for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.3

This SR requires verifying that an SX flow rate greater than or equal to the design flow rate assumed in the safety analyses (i.e., 2660 gpm) to each containment cooling unit (RCFC) will be achieved with the primary containment refrigeration units in their specified safety configuration described in UFSAR Section 9.4.8 (Ref. 2). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME (Inservice Testing) Code of Record. Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High-3 pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The surveillance of containment sump isolation valves is also required by SR 3.5.2.5. A single surveillance may be used to satisfy both requirements.

SR 3.6.6.7

This SR requires verification that each containment cooling train actuates upon receipt of an actual or simulated safety injection signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.8

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test following maintenance that could result in nozzle blockage or following fluid flow through the nozzles is considered adequate to detect obstruction of the nozzles.

SR 3.6.6.9

Containment Spray System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the containment spray trains and may also prevent water hammer and pump cavitation.

Selection of Containment Spray System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings,

BASES

SURVEILLANCE REQUIREMENTS (continued)

isometric drawings, plan and elevation drawings, and calculations. The design review is 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 configuration, such as stand-by versus operating conditions.

The Containment Spray 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 criteria 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 Containment Spray 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.

Containment Spray 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.
2. UFSAR, Section 9.4.8.
3. UFSAR, Section 6.5.2.
4. 10 CFR 50, Appendix K.
5. UFSAR, Section 6.2.1.1.3.
6. UFSAR, Section 6.2.2.
7. UFSAR, Section 6.2.

This page intentionally left blank.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System. It provides an available inventory of sodium hydroxide (NaOH) that is added to the containment spray and is accumulated in the containment sump. The resulting pH of the sump water will be ≥ 8.0, thus ensuring that iodine in the sump water will not re-evolve and be available for release from the containment to the environment. The Spray Additive System is described in UFSAR Section 6.5.2 (Ref. 1).

Airborne radioiodine in its various forms is the fission product of primary concern in the evaluation of a design basis Loss of Coolant Accident (LOCA). It is absorbed by the spray from the containment atmosphere. To enhance the iodine retention, the containment sump water is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, NaOH is the preferred spray additive. The NaOH added to the spray also ensures an equilibrium sump pH value of ≥ 8.0 and ≤ 10.5 of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine, while minimizing the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The Spray Additive System consists of one spray additive tank that is shared by the two trains of spray additive equipment. Each train of equipment provides a flow path from the spray additive tank to a containment spray pump and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line.

BASES

BACKGROUND (continued)

An automatic or manual Containment Spray System actuation signal opens the valves from the spray additive tank to the eductor (CS019A/B), the discharge valve to the eductor from the CS pump discharge (CS010A/B), if not already open, and the isolation valve into containment (CS007A/B); in addition to starting the CS pumps. The 30% to 36% NaOH solution is drawn into the spray pump suctions. The spray additive tank capacity provides for the addition of NaOH solution to water sprayed into the containment from either the Refueling Water Storage Tank (RWST) during the injection phase, or recirculated from the containment sump during the recirculation phase. The inventory of NaOH in the spray additive tank assures a long term containment sump pH of ≥ 8.0. The percent solution and volume of solution sprayed into containment ensures a long term containment sump pH of ≥ 8.0 and ≤ 10.5. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of spray operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

APPLICABLE SAFETY ANALYSES

The Spray Additive System is essential to prevent re-evolution of iodine collected in the sump following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that 82.5% of containment is covered by the spray (Ref. 2).

The accident analysis assumes that the Spray Additive System is initiated after start of the DBA. The accident analysis does not credit iodine removal due to NaOH in the spray droplets, but only credits NaOH in the containment sump for pH control thus ensuring that iodine in the sump water will not re-evolve and be available for release from the containment to the environment.

The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the useable spray additive tank volume is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The Spray Additive System is necessary to prevent re-evolution of radioactive iodine collected in the sump into the containment atmosphere in the event of a design basis LOCA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow in either the injection or the recirculation phase to increase the sump water pH to a value ≥ 8.0. This minimum pH assures retention of iodine collected in the containment sump. An upper bound on pH of 10.5 prevents conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the Spray Additive System is inoperable, it must be restored to OPERABLE within 7 days. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 7 day Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

BASES

ACTIONS (continued)

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the Spray Additive System and is reasonable when considering the driving force for a release of radioiodine from the Reactor Coolant System is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.2

To provide effective iodine retention in the containment sump, the containment sump water must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the long term containment sump water is at the correct pH level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.5

To ensure that the correct pH level is established in the borated water solution provided by the Containment Spray System, the flow rate in the Spray Additive System is verified. This SR provides assurance that the correct amount of NaOH will be metered into the flow path in each CS train upon Containment Spray System initiation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.5.2.
2. NUREG-0800, Section 6.5.2, Revision 2, December 1988.
3. UFSAR, Chapter 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Containment Sump

BASES

Background

The containment recirculation sump provides a borated water source to support recirculation of coolant from the containment recirculation sump for residual heat removal, emergency core cooling, and containment cooling during accident conditions.

The containment recirculation sumps supply both trains of the Emergency Core Cooling System (ECCS) and the Containment Spray System during any accident that requires recirculation of coolant from the containment recirculation sumps. The recirculation mode is initiated when the pump suction is transferred to the containment recirculation sump on low Refueling Water Storage Tank (RWST) level, which ensures the containment recirculation sump has enough water to supply the net positive suction head to the ECCS and Containment Spray System pumps. The containment recirculation sumps include two separate sumps, fully redundant, each servicing one train of the ECCS.

The containment recirculation sump contains strainers to limit the quantity of the debris materials from entering the sump suction piping. Debris accumulation on the strainers can lead to undesirable hydraulic effects including air ingestion through vortexing or deaeration, and reduced net positive suction head (NPSH) at pump suction piping.

While the majority of debris accumulates on the strainers, some fraction penetrates the strainers and is transported to downstream components in the ECCS, Containment Spray System, and the Reactor Coolant System (RCS). Debris that penetrates the strainer can result in wear to the downstream components, blockages, or reduced heat transfer across the fuel cladding. Excessive debris in the containment recirculation sump water source could result in insufficient recirculation of coolant during the accident, or insufficient heat removal from the core during the accident.

BASES

APPLICABLE SAFETY ANALYSIS

During all accidents that require recirculation, the containment recirculation sump provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it supports residual heat removal, emergency core cooling, and containment cooling during an accident. It also provides a source of negative reactivity (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating," B 3.5.3, "ECCS - Shutdown," and B 3.6.6, "Containment Spray and Cooling Systems."

UFSAR Section A1.82 (Ref. 2) references evaluations that confirm long-term core cooling is assured following any accident that requires recirculation from the containment sump.

The containment recirculation sump satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two containment recirculation sumps are required to ensure a source of borated water to support ECCS and Containment Spray System OPERABLILITY. A containment recirculation sump consists of the containment drainage flow paths, the containment recirculation sump strainers, a trash rack structure, vertical grating on the perimeter and checkered plate on top, protecting the openings for both sumps. The trash rack prevents debris sliding along the floor from reaching the screens, the containment recirculation sump strainers, the pump suction trash racks, and the inlet to the ECCS and Containment Spray System piping. An OPERABLE containment sump has no structural damage or abnormal corrosion that could prevent recirculation of coolant and will not be restricted by containment accident generated and transported debris.

BASES

LCO (continued)

Containment accident generated and transported debris consists of the following:

a. Accident generated debris sources - Insulation, coatings, and other materials which are damaged by the high-energy line break (HELB) and transported to the containment recirculation sump. This includes materials within the HELB zone of influence and other materials (e.g., unqualified coatings) that fail due to the post-accident containment environment following the accident;

b. Latent debris sources - Pre-existing dirt, dust, paint chips, fines or shards of insulation, and other materials inside containment that do not have to be damaged by the HELB to be transported to the containment recirculation sump; and

c. Chemical product debris sources - Aluminum, zinc, carbon steel, copper, and non-metallic materials such as paints, thermal insulation, and concrete that are susceptible to chemical reactions within the post-accident containment environment leading to corrosion products that are generated within the containment recirculation sump pool or are generated within containment and transported to the containment sump.

Containment debris limits are listed in analyses referenced in UFSAR Section A1.82 (Ref 2.)

APPLICABILITY

In MODES 1, 2, 3, and 4, containment recirculation sump OPERABILITY requirements are dictated by the ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the containment sump must also be OPERABLE to support their operation.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the containment recirculation sump is not required to be OPERABLE in MODES 5 or 6.

BASES

Actions

A.1, A.2, and A.3

Condition A is applicable when there is a condition which results in containment accident generated and transported debris exceeding the analyzed limits. Containment debris limits are listed in analyses referenced in UFSAR Section A1.82 (Ref. 2).

Immediate action must be initiated to mitigate the condition. Examples of mitigating actions are:

- Removing the debris source from containment or preventing the debris from being transported to the containment sump;
- Evaluating the debris source against the assumptions in the analysis
- Deferring maintenance that would affect availability of the affected systems and other LOCA mitigating equipment;
- Deferring maintenance that would affect availability of primary defense-in-depth systems, such as containment coolers;
- Briefing operators on LOCA debris management actions; or
- Applying an alternative method to establish new limits.

While in this condition, the RCS water inventory balance, SR 3.4.13.1, must be performed at an increased Frequency of once per 24 hours. An unexpected increase in RCS leakage could be indicative of an increased potential for an RCS pipe break, which could result in debris being generated and transported to the containment recirculation sumps. The more frequent monitoring allows operators to act in a timely fashion to minimize the potential for an RCS pipe break while the containment sumps are inoperable.

For the purposes of applying LCO 3.0.6 and the Safety Function Determination Program while in Condition A, two containment recirculation sumps are considered a single support system for all ECCS and Containment Spray System trains because containment accident generated and transported debris issues that would render one sump inoperable would render all of the sumps inoperable.

BASES

ACTIONS (continued)

The inoperable containment recirculation sump(s) must be restored to OPERABLE status in 90 days. A 90-day Completion Time is reasonable for emergent conditions that involve debris in excess of the analyzed limits that could be generated and transported to the containment recirculation sump under accident conditions. The likelihood of an initiating event in the 90-day Completion Time is very small and there is margin in the associated analyses. The mitigating actions of Required Action A.1 provide additional assurance that the effects of debris in excess of the analyzed limits will be mitigated during the Completion Time.

B.1

When the containment recirculation sump(s) is inoperable for reasons other than Condition A, such as blockage, structural damage, or abnormal corrosion that could prevent recirculation of coolant, it must be restored to OPERABLE status within 7 days. The 7 day Completion Time takes into account the reasonable time for repairs, and low probability of an accident that requires the containment recirculation sump occurring during this period.

Required Action B.1 is modified by two Notes. The first Note indicates that the applicable Conditions and Required Actions of LCO 3.5.2, "ECCS - Operating," and LCO 3.5.3, "ECCS - Shutdown," should be entered if an inoperable containment sump results in an inoperable ECCS train. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.6.6, "Containment Spray and Cooling Systems," should be entered if an inoperable containment sump results in an inoperable Containment Spray System train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

C.1 and C.2

If the containment recirculation sump cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed 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.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.8.1</u> Periodic inspections are performed to verify the containment recirculation sump does not show current or potential debris blockage, structural damage, or abnormal corrosion to ensure the operability and structural integrity of the containment recirculation sump (Ref. 1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
References	1. UFSAR, Sections 6.2.1 and 15.6.5. 2. UFSAR, Section A1,82, Regulatory Guide 1.82, Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the Reactor Coolant Pressure Boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available. The MSSVs also serve as Containment Isolation Valves (CIVs); however, the CIV function is addressed in LCO 3.6.3, "Containment Isolation Valves."

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the UFSAR, Section 10.3.1 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of steam generator design pressure for any Anticipated Operational Occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis. The MSSVs are also credited as CIVs (refer to LCO 3.6.3).

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events (i.e., RCS heatup events), which are presented in the UFSAR, Section 15.2 (Ref. 3). Of these, the full power turbine trip without steam dump is typically the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis demonstrates that the transient response for turbine trip occurring from full power without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. This accident is analyzed for two specific cases, one for minimum Departure from Nucleate Boiling Ration (DNBR) and one for maximum RCS and secondary pressures. For the minimum DNBR case, the analysis is performed assuming operation of the pressurizer Power Operated Relief Valves (PORVs) and the pressurizer spray valves in order to reduce RCS pressure and, thus, yield a minimum DNBR. Pressurizer safety valves are also assumed to be available. For the pressure case, no credit is taken for operation of the pressurizer PORVs or pressurizer spray valves. This case credits reactor trip on high pressurizer pressure and operation of the pressurizer safety valves. This analysis demonstrates that RCS integrity is maintained by showing that the maximum RCS pressure does not exceed 110% of the design pressure. All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to ≤ 110% of the steam generator design pressure.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled Rod Cluster Control Assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the steam generator PORVs or condenser steam dump valves. The UFSAR Section 15.4 safety analysis of the uncontrolled RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The UFSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system

BASES

APPLICABLE SAFETY ANALYSES (continued)

overpressurization may be determined by system transient analyses or conservatively arrived at by a simple heat balance calculation. Plant specific sensitivity studies demonstrate that in some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, with one or more MSSVs on one or more steam generators inoperable, during an RCS heatup event (e.g, turbine trip) when the Moderator Temperature Coefficient (MTC) is positive, the reactor power may increase above the initial value. An uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds that combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for any number of inoperable MSSVs on one or more steam generators it is necessary to prevent a power increase by lowering the Power Range Neutron Flux-High reactor trip setpoint to an appropriate value.

The MSSVs are assumed to have two active and one passive failure modes. The active failure modes are spurious opening, and failure to reclose once opened. The passive failure mode is failure to open upon demand.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The accident analysis requires five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients. The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2, and the DBA analysis.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, to relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the INSERVICE TESTING PROGRAM.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB or Main Steam System integrity.

BASES

APPLICABILITY

In MODES 1, 2, and 3 five MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1 and A.2

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

With one or more MSSVs inoperable on one or more steam generators, a reactor power reduction alone may result in insufficient total steam flow capacity provided by the remaining OPERABLE MSSVs to preclude overpressurization in the event of an RCS heatup event when the MTC is positive since reactor power may increase. Furthermore, reactor power may increase due to a reactivity insertion event, such as an uncontrolled RCCA bank withdrawal at partial power event, such that the flow capacity of the turbine and remaining OPERABLE MSSVs is insufficient. Therefore, Required Action A.1 requires an appropriate reduction in reactor power within 4 hours. An additional 32 hours is allowed in Required Action A.2 to reduce the Power Range Neutron Flux-High reactor trip setpoints. The Completion Time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

BASES

ACTIONS (continued)

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined by a simple heat balance calculation as described in the attachment to Reference 4, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties. The following equation is used to determine the maximum allowable power level for continued operation with inoperable MSSV(s):

$$Maximum\ Allowable\ Power = \frac{100}{Q}\left(\frac{w_S\ h_{fg}\ N}{K}\right)$$

Where:

Q	=	Nominal NSSS power rating of the plant (including reactor coolant pump heat), in Mwt (= 3659 Mwt).
K	=	Conversion factor = 947.82 (BTU/sec)/Mwt.
w_s	=	minimum total steam flow rate capability of the OPERABLE MSSVs on any one steam generator at the highest OPERABLE MSSV opening pressure including tolerance and accumulation, as appropriate, in lbm/sec.
h_{fg}	=	Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, in BTU/lbm.
N	=	Number of loops in the plant (= 4).

The maximum allowable power level determined by this simple heat balance calculation was adjusted lower by 7.4% RTP to account for Nuclear Instrumentation System trip channel uncertainties. Plant specific sensitivity studies demonstrate that use of this simple heat balance calculation is sufficiently conservative at all power levels if an allowance of 7.4% of Nuclear Instrumentation System trip channel uncertainty and a MSSV setpoint tolerance of 3% for Unit 1 (4% for Unit 2) are assumed in plant specific

BASES

ACTIONS (continued)

analyses. The Nuclear Instrumentation System trip channel uncertainty assumption used in the plant specific analyses is bounded by the calculated value. The MSSV setpoint tolerance assumption used in the plant specific analyses is bounded by the setpoint tolerance specified in Table 3.7.1-2.

Required Action A.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in Mode 1. In Modes 2 and 3 the reactor protection system trips specified in LCO 3.3.1, “Reactor Trip System Instrumentation,” provide sufficient protection.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging plant systems.

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status or the Required Actions cannot be completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the INSERVICE TESTING PROGRAM. The ASME Code (Ref. 5) requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 6). According to Reference 6, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

d. Compliance with owner's seat tightness criteria; and

e. Verification of the balancing device integrity on balanced valves.

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2, in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. UFSAR, Section 10.3.1.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.
3. UFSAR, Section 15.2.
4. NRC Information Notice 94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.
6. ANSI/ASME OM-1-1987 and applicable Addenda.

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a High Energy Line Break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to containment. The MSIVs are downstream from the Main Steam Safety Valves (MSSVs), to prevent MSSV isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIV is a gate valve with dual-redundant hydraulic actuator trains. Either actuator train can independently perform the safety function to fast-close the MSIV on demand. Each actuator train consists of a hydraulic accumulator controlled by solenoid valves on the associated MSIV. For each MSIV, one actuator train is associated with ESF Division 1, and one actuator train is associated with ESF Division 2.

A pneumatic and hydraulic actuator train is composed solely of skid-mounted components at the MSIV location. The actuator train does not include any portion of the analog channels or protection system actuation logic and actuation relays that provide inputs to the valve actuator trains. LCO 3.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation," provides separate Conditions, Required Actions, and Surveillance Requirements for the analog channels and protection system logic and relays.

The MSIVs close on a main steam isolation signal generated by Steam Line Low Pressure, Steam Line High Negative Rate, or High-2 containment pressure. The MSIVs fail as is on loss of control or actuation power.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same automatic closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the UFSAR, Section 10.3 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the analysis for the large Steam Line Break (SLB) outside containment, discussed in the UFSAR, Section 15.1.5 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the UFSAR, Section 6.2 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System (RCS) cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs and their associated actuator trains in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

An MSIV actuator train is considered OPERABLE when it is capable of fast-closing the associated MSIV on demand and within the required isolation time. This includes having adequate accumulator pressure to support fast-closure of the MSIV within the required isolation time.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in exposures comparable to the 10 CFR 50.67 (Ref. 4) limits or the NRC staff approved licensing basis.

BASES

APPLICABILITY

The MSIVs and required actuator trains must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function. In MODE 4 the steam generator energy is low.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With a single actuator train inoperable on one MSIV, action must be taken to restore the inoperable actuator train to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The 7-day Completion Time is reasonable in light of the dual-redundant actuator train design such that with one actuator train inoperable, the affected MSIV is still capable of closing on demand via the remaining OPERABLE actuator train. The 7-day Completion Time takes into account the redundant OPERABLE actuator train to the MSIV, reasonable time for repairs, and the low probability of an event occurring that requires the inoperable actuator train to the affected MSIV.

B.1

With one actuator train on one MSIV inoperable; and one actuator train on an additional MSIV inoperable, such that the inoperable actuator trains are not in the same ESF Division, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. With one actuator train inoperable on two different MSIVs that are not in the same ESF Division, there is an increased likelihood that an additional failure (such as the failure of an actuator logic train) could cause one MSIV to fail to close. The 72-hour Completion Time is reasonable since the dual-redundant actuator train design ensures that with only one actuator train on each of two affected MSIVs inoperable, each MSIV is still capable of closing on demand.

BASES

ACTIONS (continued)

C.1

With one actuator train on one MSIV inoperable; and one actuator train on an additional MSIV inoperable, such that both inoperable actuator trains are in the same ESF Division, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 24 hours. The 24-hour Completion Time provides a reasonable amount of time for restoring at least one actuator train since the dual-redundant actuator train design for each MSIV ensures that a single inoperable actuator train cannot prevent the affected MSIV(s) from closing on demand. With two actuator trains inoperable in the same ESF Division, an additional failure (such as the failure of an actuator logic train in the other ESF Division) could cause both affected MSIVs to fail to close on demand. The 24 hour Completion Time takes into account the redundant OPERABLE actuator trains to the affected MSIVs and the low probability of an event occurring that requires the inoperable actuator trains to the affected MSIVs.

D.1

Required Action D.1 provides assurance that the appropriate Condition is entered for the affected MSIV if its associated actuator trains become inoperable. Failure of both actuator trains for a single MSIV results in the inability to close the affected MSIV on demand.

E.1

With three or more MSIV actuator trains inoperable or when Required Action A.1, B.1, or C.1 are not completed within the required Completion Time, the affected MSIVs may be incapable of closing on demand and must be immediately declared inoperable. Having three actuator trains inoperable could involve two inoperable actuator trains on one MSIV and one inoperable actuator train on another MSIV, or an inoperable actuator train on each of three MSIVs, for which the inoperable actuator trains could all be in the same ESF Division or be staggered among the two ESF Divisions.

Depending on which of these conditions or combinations is in effect, the condition or combination could mean that all of the affected MSIVs remain capable of closing on demand (due

ACTIONS (continued)

to the dual-redundant actuator train design), or that at least one MSIV is inoperable, or that with an additional single failure up to three MSIVs could be incapable of closing on demand. Therefore, in some cases, immediately declaring the affected MSIVs inoperable is conservative (when some or all of the affected MSIVs may still be capable of closing on demand even with a single additional failure), while in other cases it is appropriate (when at least one of the MSIVs would be inoperable, or up to three could be rendered inoperable by an additional single failure). Required Action E.1 is conservatively based on the worst-case condition and therefore requires immediately declaring all the affected MSIVs inoperable.

F.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours or in accordance with the Risk Informed Completion Time Program. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

Condition F is entered when one MSIV is inoperable in MODE 1, including when both actuator trains for one MSIV are inoperable. When only one actuator train is inoperable on one MSIV, Condition A applies.

The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

G.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition H would be entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

H.1 and H.2

Condition H is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition F.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

I.1 and I.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5 seconds on an actual or simulated actuation signal (from each actuator train). The MSIV closure time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. Based on ASME Code (Ref. 5), the MSIVs are not closure time tested at power.

The Frequency is in accordance with the INSERVICE TESTING PROGRAM. This test is conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note. This Note allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

This SR verifies that each actuator train can close its respective MSIV on an actual or simulated actuation signal. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. This Note allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 15.1.5.
3. UFSAR, Section 6.2.
4. 10 CFR 50.67.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.7 PLANT SYSTEMS

B 3.7.3 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours). I-131, with a half life of 8.04 days, concentrates faster than it decays, but does not reach equilibrium because of blowdown and other losses.

With the specified activity limit, the resultant dose would be within 10 CFR 50.67 (Ref. 1) limits assuming a secondary coolant release following a trip from full power.

BASES

APPLICABLE SAFETY ANALYSES

The accident analysis of the Main Steam Line Break (MSLB), as discussed in the UFSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.1 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed the 10 CFR 50.67 limits (Ref. 1).

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and Steam Generator (SG) Power Operated Relief Valves (PORVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generators are assumed to discharge steam and any entrained activity through the MSSVs and SG PORVs during the event. Since no credit is taken in the analysis for activity plate out or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.1 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to the required limits (Ref. 1).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity is not within limits, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.67.

2. UFSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.4 Steam Generator (SG) Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The SG PORVs provide a method for cooling the unit to Residual Heat Removal (RHR) entry conditions should the preferred heat sink via the Steam Dump System to the condenser not be available, as discussed in the UFSAR, Section 10.3 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The SG PORVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Steam Dump System. The SG PORVs also serve as Containment Isolation Valves (CIVs); however, the CIV function is addressed in LCO 3.6.3, "Containment Isolation Valves."

One SG PORV line for each of the four steam generators is provided. Each SG PORV line consists of one SG PORV and an associated block valve.

The SG PORVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The SG PORVs are equipped with electrohydraulic actuators to permit control of the cooldown rate.

A description of the SG PORVs is found in Reference 1. The SG PORVs are powered from Class 1E buses. The valve operators and control circuit for the A and D SG PORVs are powered by Engineered Safety Feature (ESF) Division 1 and the B and C SG PORVs are powered by ESF Division 2. To address the limiting passive electrical failure (i.e., loss of a Division 1 or Division 2 480 V ESF bus), the C and D SG PORVs are powered from an uninterruptible power supply system with battery backup to ensure that a passive electrical failure does not render two SG PORVs on the intact SGs inoperable. In addition, handpumps are provided for local manual operation.

BASES

APPLICABLE SAFETY ANALYSES

The SG PORV lines provide an alternate method for cooling the unit to RHR entry condition whenever the preferred heat sink via the Steam Dump System to the condenser is unavailable due to a loss of offsite power. Prior to operator actions to cool down the unit, the SG PORVs and main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the SG pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event (Ref. 2), the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured SG. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. After primary to secondary break flow termination, it is assumed that SG PORVs on two intact SGs are used to cool the RCS down to 350°F. Thus, the SGTR is the limiting event for the SG PORVs. The number of SG PORVs required to be OPERABLE to satisfy the SGTR accident analysis requirements depends upon the number of reactor coolant system loops and consideration of a single failure assumption regarding the failure of one SG PORV to open on demand.

In addition, the SGTR analysis considers SG overfill. The limiting single failure with respect to SG overfill is the failure of one SG PORV on an intact SG to open when required for cooldown of the RCS. The analysis assumes four SG PORVs are OPERABLE at the start of the SGTR event. One SG PORV is on the ruptured SG, another SG PORV is assumed to fail to open and the remaining SG PORVs are used to perform the RCS cooldown. The analysis shows that cooldown using two SG PORVs results in no SG overfill.

The SG PORVs are equipped with manual block valves in the event a SG PORV fails to close during use. The SG PORVs are also credited as CIVs (refer to LCO 3.6.3).

The SG PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Four SG PORV lines are required to be OPERABLE. One SG PORV line is required from each of four steam generators to ensure that at least two SG PORV lines are available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second SG PORV line on an unaffected steam generator. To ensure that at least two SG PORVs on intact SGs are available in the event of a passive electrical failure, the uninterruptible power supply system with at least a 90 minute battery backup supply to the C and D SG PORVs must be OPERABLE. The block valves must be OPERABLE to isolate a failed open SG PORV line. A closed block valve does not render it or its SG PORV line inoperable. Operator action time to open the block valve is supported in the accident analysis.

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an SGTR event in which the condenser is unavailable for use with the Steam Dump System.

A SG PORV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand.

APPLICABILITY

In MODES 1, 2, and 3, the SG PORVs are required to be OPERABLE.

In MODE 4, the pressure and temperature limitations are such that the probability of an SGTR event requiring SG PORV operation is low. In addition, the RHR system is available to provide the decay heat removal function in MODE 4. Therefore, the SG PORV lines are not required OPERABLE in MODE 4.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one SG PORV line inoperable, action must be taken to restore OPERABLE status within 30 days or in accordance with the Risk Informed Completion Time Program. The 30 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE SG PORV lines, a nonsafety grade backup in the Steam Dump System, and MSSVs.

BASES

ACTIONS (continued)

B.1

With two SG PORV lines inoperable, action must be taken to restore one SG PORV line to OPERABLE status. Since the block valve can be closed to isolate a SG PORV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable SG PORV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the SG PORV lines. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

C.1

With three or more SG PORV lines inoperable, action must be taken to restore all but one SG PORV line to OPERABLE status. Since the block valve can be closed to isolate a SG PORV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable SG PORV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the SG PORV lines.

D.1 and D.2

If the SG PORV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the SG PORVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the SG PORVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of a SG PORV during a unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.2

The function of the block valve is to isolate a failed open SG PORV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 15.6.3.

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AF) System

BASES

BACKGROUND

The AF System automatically supplies feedwater to the Steam Generators (SGs) to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AF pumps normally take suction from the condensate storage tank (CST) (LCO 3.7.6) and pump to the steam generator secondary side via separate and independent connections to the feedwater piping outside containment. If the CST is not available, AF can be supplied by the Essential Service Water System. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the Main Steam Safety Valves (MSSVs) (LCO 3.7.1) or SG Power Operated Relief Valves (PORVs) (LCO 3.7.4). If the main condenser is available, steam may be released via the steam dump valves and recirculated to the CST.

The AF System consists of a motor driven AF pump and a diesel driven pump configured into two trains. Each pump provides 100% of the required AF capacity to the steam generators, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. The motor driven AF pump is powered from an independent Class 1E power supply and feeds four steam generators. The diesel driven AF pump is powered from an independent diesel and also feeds four steam generators. The diesel driven AF pump is supported by a diesel engine, an independent battery system, an essential service water booster pump, and a fuel oil day tank. Thus, the requirement for diversity in motive power sources for the AF System is met.

The AF System is capable of supplying, but does not normally supply, feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

One pump at full flow is sufficient to remove decay heat and cool the unit to Residual Heat Removal (RHR) entry conditions.

BASES

BACKGROUND (continued)

The AF System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AF System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the SG PORVs.

The AF System actuates automatically on low-2 steam generator water level, Safety Injection and Undervoltage (UV) on the Reactor Coolant Pump buses. The motor driven AF pump also actuates on an UV on bus 141(241).

The AF System is discussed in the UFSAR, Section 10.4.9 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AF System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AF System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the maximum steam pressure inside an intact steam generator during the long term cooling portion of the design basis accident (i.e., after steam line isolation occurs). This maximum steam pressure is 1250 psia (Ref. 2).

In addition, the AF System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AF flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AF System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of normal feedwater.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition, the minimum available AF flow and system characteristics are serious considerations in the analysis of a small break Loss Of Coolant Accident (LOCA) and loss of offsite power (Ref. 3).

The AF System design is such that it can perform its function following an FWLB between the main feedwater isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of one AF pump. The AF lines to the SGs are orificed such that sufficient flow is delivered to the non faulted SGs. Reactor trip is assumed to occur when the faulted SG reaches the low-low level setpoint. Sufficient flow would be delivered to the intact steam generators by the other AF pump.

During the loss of all AC power events, the Engineered Safety Feature Actuation System (ESFAS) automatically actuates the AF diesel driven pump and associated controls to ensure an adequate supply to the steam generators during loss of power. Valves which can be manually controlled are provided for each AF line to control the AF flow to each steam generator during loss of all AC power events.

AF flow is also an important consideration in the Steam Generator Tube Rupture (SGTR) event (Ref. 4). For the SGTR event, isolation of AF flow is an important recovery action. This flow path is normally isolated with the motor operated AF013 valves. Prior to isolation with AF013 valves, flow to the ruptured SG is limited by the control function of the AF005 valves.

The AF System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Since the AF005 valve is a backup and diverse method to isolate flow to the faulted SG in a SGTR event, this function does not satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii). Administrative requirements for this function are addressed in the Technical Requirements Manual.

BASES

LCO	This LCO provides assurance that the AF System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Two independent AF pumps in two diverse trains are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering one of the pumps from the emergency buses. The second AF pump is powered by a different means, a diesel engine. The AF System is configured into two trains. The AF System is considered OPERABLE when the components and flow paths required to provide redundant AF flow to the steam generators are OPERABLE. This requires that the motor driven AF pump and the diesel driven AF pump be OPERABLE and capable of supplying AF to each steam generator. The associated piping, valves, instrumentation, and controls in the required flow paths to perform the safety related function are also required to be OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, the AF System is required to be OPERABLE in the event that it is called upon to function when feedwater is lost. In MODE 4, 5, or 6, the steam generators are not normally used for heat removal, and the AF System is not required.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AF train when entering MODE 1. There is an increased risk associated with entering MODE 1 with an AF train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With one of the required AF trains (pump or flow path) inoperable, action must be taken to restore OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AF System, time needed for repairs, and the low probability of a DBA occurring during this time period.

B.1 and B.2

When Required Action A.1 cannot be completed within the required Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 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 plant systems.

C.1

If both AF trains are inoperable, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AF train to OPERABLE status.

Required Action C.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AF train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition. In addition, the Completion Times of Required Actions which are suspended are also suspended.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AF System provides assurance that the proper flow paths will exist for AF operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.5.2

This SR provides verification that the level of fuel oil in the day tank is at or above the level required by the diesel driven pump for delivery of the 212,000 gallon minimum condensate water supply. The level is expressed as an equivalent volume in gallons.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.5.3

This SR verifies that each diesel driven AF pump is run for greater than or equal to 15 minutes.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4

Verifying that each AF pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AF pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref. 5). Because it is undesirable to introduce cold AF into the steam generators while they are operating, this testing is performed on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 5) (only required at 3 month intervals) satisfies this requirement.

SR 3.7.5.5

This SR verifies that AF can be delivered to the steam generators in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.6

This SR verifies that the AF pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AF pump starts automatically on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.5.7

This SR verifies that the AF is properly aligned by verifying the flow paths from the CST to each steam generator prior to entering MODE 2 after more than 30 days in any combination of MODE 5, MODE 6, or defueled. OPERABILITY of AF flow paths must be verified before sufficient core heat is generated that would require the operation of the AF System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To ensure AF System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.8

The tests of fuel oil are a means of assuring it has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. The tests, limits, and applicable ASTM standards are listed in the Diesel Fuel Oil Testing Program, as described in Specification 5.5.13.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D5452-98 (Ref. 6). This method involves a determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

Fuel Oil to the Auxiliary Feedwater Pump Day Tank is supplied from the outside fuel oil storage tanks. These tanks are also subject to the requirements of the Diesel Fuel Oil Testing Program, as described in Specification 5.5.13.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

BASES

REFERENCES

1. UFSAR, Section 10.4.9.
2. Westinghouse Nuclear Safety Evaluation Checklist, SECL 90-469, Revision 1, "Byron/Braidwood Units 1 and 2, Relaxation of MSSV Setpoint Tolerance to +/- 3% - Revised SECL."
3. UFSAR, Section 15.2.
4. UFSAR, Section 15.6.3.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.
6. ASTM Standards, D5452-98.
7. Calculation BYR10-103, AF Diesel Driven Pump Fuel Consumption and Day Tank Requirements.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a nonsafety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AF) System (LCO 3.7.5) which feeds the steam generators. The steam produced is released to the atmosphere by the Main Steam Safety Valves (MSSVs) or the steam generator power operated relief valves when the condenser is not available. The AF pumps normally operate with recirculation to the CST.

When the main steam isolation valves or their associated bypass valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam dump valves. The condensed steam is returned to the CST via the condenser overflow line into the condensate makeup header using the condensate booster pumps. This has the advantage of conserving condensate while minimizing releases to the environment.

The Essential Service Water (SX) System provides a safety related, Seismic Category I backup to the CST. The SX System is automatically aligned to provide AF based on system conditions and pump start signals.

Branch Technical Position (BTP) RSB 5-1 (Ref.1) provides the design requirements of the Residual Heat Removal System. The design requirements of BTP RSB 5-1 for the AF supply require a Seismic Category I supply unless it can be shown that for Class 2 plants an adequate alternate Seismic Category I source is available. An evaluation of the Byron design concluded that the technical requirements of BTP RSB 5-1 as they apply to Class 2 plants were satisfied (Ref. 2). The requirements for cooling water supply were satisfied based on having a large safety-related backup supply of cooling water.

A description of the CST is found in the UFSAR, Section 9.2.6 (Ref. 3).

BASES

APPLICABLE SAFETY ANALYSIS	The CST provides cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the UFSAR, Chapters 6 and 15 (Refs. 4 and 5, respectively). The CST provides the normal (preferred) supply to the AF System (Ref. 6). However, this function is not required to maintain plant safety because the SX System provides a safety-related backup to the AF System. The CST is not required to achieve safe reactor shutdown conditions or for accident prevention or accident mitigation with the exception of Station Blackout. The CST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
	LCO The specified level assures the required useable volume of approximately 212,000 gallons is met. This volume is sufficient to maintain the RCS in MODE 3 at normal operating pressure and temperature for 2 hours, followed by a cooldown to RHR entry conditions at 50°F/hour, followed by a period not longer than one-hour to allow warmup of the RHR pumps prior to placing the RHR system into service in shutdown cooling mode. The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the CST is required to be OPERABLE.

In MODE 4, 5, or 6, the CST is not required because the AF System is not required.

ACTIONS

A.1 and A.2

If the CST level is not within limits, the OPERABILITY of the backup water supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup water supply must include verification that the flow paths from the backup water supply to the AF pumps are OPERABLE, and that the backup supply has the required volume of water available. The normal backup supply is the SX System. The CST must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time or the backup water supply is not available, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.7.6.1</u> This SR verifies that the CST contains the required volume of cooling water. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System." 2. NRC Safety Evaluation, "Natural Circulation Cooldown, Byron Units 1 and 2 and Braidwood Units 1 and 2," dated November 4, 1988. 3. UFSAR, Section 9.2.6. 4. UFSAR, Chapter 6. 5. UFSAR, Chapter 15. 6. UFSAR, Section 10.4.9.

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CC) System

BASES

BACKGROUND

The CC System is a shared system which provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CC System also provides this function for various nonessential components, as well as the spent fuel pool. The CC System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Essential Service Water (SX) System, and thus to the environment.

The shared CC system consists of five pumps (four unit-specific and one common), three heat exchangers (two unit-specific and one common), and two unit-specific surge tanks. The heat exchangers are cooled by SX. The surge tanks are provided to accommodate expansion and contraction due to temperature changes or inleakage, as well as makeup capability. Each surge tank is partitioned by a baffle which protects against complete draining of the tank in case a leak develops in one train during post accident alignments. The surge tank design and associated piping provide surge tank functioning separately to each flow path.

The two unit-specific CC pumps per unit are supplied, one from each 4.16 kV ESF bus. The power supply for the common CC pump can be from any one of the four 4.16 kV ESF buses (141, 142, 241, or 242). For maintaining complete separation, a separate 4.16 kV bus (CC Pump bus), located on the 383 foot elevation of the auxiliary building, is provided. This bus consists of four separate 4.16 kV switchgear cubicles, each connected and interlocked to one of the four ESF divisions. Only one breaker is provided and is racked into the cubicle from which the common CC pump is supplied.

BASES

BACKGROUND (continued)

The system is normally aligned with one unit served by two heat exchangers (one unit-specific and the common) and the other unit served by its unit-specific heat exchanger. Normally, the unit with two heat exchangers supplies cooling to both units' "A" train Residual Heat Removal (RHR) heat exchanger and pump. During operation in MODES 1, 2, 3, and 4, one pump and flow path (which includes at least one CC heat exchanger) per unit are capable of serving all operating components. In the event of a Loss Of Coolant Accident (LOCA) on one unit, one pump and flow path are capable of fulfilling system requirements for that unit. The second required pump and flow path provide the required redundancy in the event of a single active or passive failure. Since the CC System is shared between the units, one heat exchanger may be credited to both units.

Piping and manual isolation valves provide the ability for the CC system to operate crosstied between the units or split into separate unit operation, as well as the capability to operate the units on a train basis depending on plant conditions. When operated on a train basis both unit's "A" RHR trains are fed from the common heat exchanger.

Each pump automatically starts on receipt of a safety injection signal or an undervoltage on the associated ESF bus.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the UFSAR, Section 9.2.2 (Ref. 1). The principal safety related function of the CC System is the removal of decay heat from the reactor via the RHR System. This may be during a normal or post accident cooldown and shutdown.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the CC System is for one CC train (one pump and flow path) to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase. The design prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System (RCS) by the Emergency Core Cooling System (ECCS) pumps.

The CC System is designed to perform its function with a single active or passive failure, assuming a loss of offsite power. The analysis considers the potential need to manually realign the system depending on the failure.

The CC System also functions to cool the unit from RHR entry conditions to MODE 5 during normal and post accident operations. The time required is a function of the number of CC and RHR trains operating. One CC train is sufficient to remove decay heat during subsequent operation. The temperature of the cooling water supplied to the various components should be ≤ 105°F during normal operation. During initial operation of the RHR system, the CC system supply water temperature may be permitted to increase to 120°F for a maximum of 3 hours. During post-LOCA operation, the CC system supply water temperature for the LOCA unit and the non-LOCA unit may increase to 128°F.

The CC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

In the event of a DBA, one CC pump, CC heat exchanger and flow path are required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water on the affected unit. To ensure this requirement is met, two pumps (from separate unit-specific ESF buses) and two flow paths (each with one CC heat exchanger and surge tank availability) must be OPERABLE, assuming the worst case single failure.

The CC System is normally operated as a shared system that provides cooling to equipment in both units. As such, some component can satisfy requirements on both units. Since the CC System is shared, the common heat exchanger and associated portions of its flow path, may be credited to both units.

Therefore, the CC System is considered OPERABLE when:

a. Two electrically independent pumps are OPERABLE;

b. Two flow paths, each consisting of a CC heat exchanger, surge tank availability, piping and valves required to supply separate RHR trains, are OPERABLE; and

c. The associated instrumentation and controls required to perform the safety related function are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CC System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CC System are determined by the systems it supports.

ACTIONS

The actions are modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," be entered if an inoperable CC train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

A.1

If a CC flow path is not OPERABLE, action must be taken to restore OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE flow path is adequate to perform the heat removal function. The inoperability of the common CC heat exchanger impacts both units' flow paths. Inoperability of a unit-specific CC heat exchanger impacts only the unit-specific flow path.

The 7 day Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, the ability to crosstie trains and units, and the low probability of a DBA occurring during this period.

B.1

If one required CC pump is inoperable, action must be taken to restore OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE CC pump is adequate to perform the heat removal function. The 7 day Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, the ability to crosstie the trains and Units, and the low probability of a DBA occurring during this period.

C.1 and C.2

If the CC flow path or pump cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Verifying the correct alignment for manual and power operated valves in the CC flow path provides assurance that the proper flow paths exist for CC operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note indicating isolation of the CC flow to individual components does not affect the OPERABILITY of the CC System. Isolation may render those components inoperable.

SR 3.7.7.2

This SR verifies the correct alignment for manual and power operated SX valves directly serving the CC heat exchangers that are not locked, sealed, or otherwise in the correct position, are in the correct position or can be aligned to the correct position. This includes the ability to align the SX system as required to support unit-specific or opposite unit operations. It also includes assuring that the requirements of the ISI and IST programs are satisfied. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

This SR verifies proper automatic operation of the CC pumps on an actual or simulated actuation signal. The CC System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.2.

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.8 Essential Service Water (SX) System

BASES

BACKGROUND

The SX System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SX System also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The unit-specific SX System consists of two separate, electrically independent, 100% capacity, safety related, cooling water trains. Each train consists of a 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned, except in the unlikely event of a Loss Of Coolant Accident (LOCA). The pumps are automatically started upon receipt of a safety injection signal or an undervoltage on the ESF bus, and all essential valves are aligned to their post accident positions (Diesel Generator (DG) supply valves are opened once the DG has reached sufficient rpm). The SX System is the backup water supply to the Auxiliary Feedwater System.

The SX System includes provisions to crosstie the trains (unit-specific crosstie), as well as provisions to crosstie the units (opposite-unit crosstie). The opposite-unit crosstie valves (1SX005 and 2SX005) must both be open to accomplish the opposite-unit crosstie. The system is normally aligned with the unit-specific crosstie valves open and the opposite-unit crosstie valves closed.

Additional information about the design and operation of the SX System, along with a list of the components served, is presented in the UFSAR, Section 9.2.1 (Ref. 1). Some of the functions served by the SX System are the removal of decay heat from the reactor via the Component Cooling Water (CC) System, the removal of heat from containment via the reactor containment fan coolers, and cooling of the DGs.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the SX System is for one SX train, in conjunction with the CC System and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2 (Ref. 2). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the Emergency Core Cooling System pumps. The SX System is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SX System, in conjunction with the CC System, also cools the unit from Residual Heat Removal (RHR) entry conditions, as discussed in the UFSAR, Section 5.4.7, (Ref. 3) to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CC and RHR System trains that are operating. One SX train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6.

Generic Letter 91-13 (Ref. 4) included risk-based recommendations for enhancing the availability of SX Systems, in the case of a loss of all SX to a particular unit. Crediting the opposite-unit SX System with an opposite-unit pump and the opposite-unit crosstie valves, was a part of the response to this Generic Letter.

The unit-specific SX System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). The opposite-unit SX System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Two unit-specific SX trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming that the worst case single active failure occurs coincident with the loss of offsite power.

A unit-specific SX train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The pump is OPERABLE; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

An opposite-unit SX train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. An opposite-unit pump is capable of performing its required unit-specific function (manually start and supply SX to the flow path);

b. A flow path from the opposite unit is established, or capable of being established (including the opposite-unit crosstie valves 1SX005 and 2SX005); and

c. The associated piping, valves, and instrumentation and controls are capable of performing the crosstie function.

APPLICABILITY

In MODES 1, 2, 3, and 4, the unit-specific SX System is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SX System and required to be OPERABLE in these MODES.

While a specific unit is in MODES 1, 2, 3, or 4, the opposite-unit SX System must be available (independent of the opposite unit's MODE or condition) for unit-specific support. This minimizes the risk associated with loss of all unit-specific SX.

In MODES 5 and 6 the OPERABILITY requirements of the unit-specific SX System are determined by the systems it supports and there are no opposite-unit SX System requirements.

BASES

ACTIONS

A.1

If one unit-specific SX train is inoperable, action must be taken to restore OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE SX train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SX train could result in loss of the SX System function in the short term. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

Required Action A.1 is modified by two Notes. The first Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources-Operating," should be entered if an inoperable SX train results in an inoperable emergency diesel generator. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," should be entered if an inoperable SX train results in an inoperable decay heat removal train. These are exceptions to LCO 3.0.6 and ensure the proper actions are taken for these components.

BASES

ACTIONS (continued)

B.1

If the opposite-unit SX train is not OPERABLE for unit-specific support, action must be taken to restore OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this Condition, if a complete loss of unit-specific SX were to occur, the SX System function would be lost. The 7 day Completion Time is based on the capabilities of the unit-specific SX System and the low probability of a DBA with a loss of all unit-specific SX occurring during this time period.

C.1 and C.2

If the unit-specific SX train or the opposite-unit SX train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

Verifying the correct alignment for manual, power operated, and automatic valves in the unit-specific SX flow path provides assurance that the proper flow paths exist for unit-specific SX operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note indicating isolation of the SX components does not affect the OPERABILITY of the SX System. Isolation of components may render those components inoperable.

SR 3.7.8.2

This SR verifies that the opposite-unit SX pump can be run for ≥ 15 minutes. This SR does not require the opposite-unit pump to supply SX to the specific unit. SR 3.7.8.2 is modified by a note that only requires this surveillance to be performed when the opposite unit is in MODE 5 or 6 or has no fuel in the reactor vessel. If the opposite unit is in MODE 1, 2, 3, or 4, its SX System is normally operating. If the opposite unit is shut down, the credited SX pump may not be operating. Therefore, the Note requires the surveillance to be performed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.3

This SR verifies proper operation of the opposite-unit SX crosstie valves (1SX005 and 2SX005). This Surveillance is not required if the opposite-unit SX crosstie valve is secured in the open position with power removed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.4

This SR verifies proper automatic operation of the unit-specific SX System valves on an actual or simulated actuation signal. The SX System is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.5

This SR verifies proper automatic operation of the unit-specific SX pumps on an actual or simulated actuation signal. The SX System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.1.
2. UFSAR, Section 6.2.
3. UFSAR, Section 5.4.7.
4. Generic Letter 91-13.

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Essential Service Water (SX) System and the Component Cooling Water (CC) System.

In addition, the UHS is the safety related source of Auxiliary Feedwater (AF) in case the Condensate Storage Tank is unavailable.

The UHS is a common system and consists of two, four cell, mechanical draft cooling towers (0A and 0B) and a makeup system. Each tower has four fans (with two speeds - high and low), which are manually actuated. Two of the Tower 0A fans are powered from Unit 1, Division 11 and two fans are powered from Unit 2, Division 21. Similarly two Tower 0B fans are powered from Unit 1, Division 12 and two fans are powered from Unit 2, Division 22.

The normal makeup to the towers is provided by the non-safety related, non-engineered safety feature, Circulating Water System. Two safety related diesel-driven makeup pumps, which take suction from the Rock River, provide makeup to each of the towers (one pump per tower). Level switches are provided to automatically start the pump on low level in the associated tower basin. In addition, a deep well pump, powered from the engineered safety feature bus associated with each tower is capable of providing makeup to either basin. The deep well pumps do not include automatic start capability. The two tower basins communicate at approximately the 64% basin level.

Each makeup source is capable of supplying sufficient makeup water to maintain adequate basin inventory. Makeup is required to compensate for AF supply, as well as drift, evaporation and blowdown losses, resulting from design basis Loss Of Coolant Accident (LOCA) conditions in one unit concurrent with the safe shutdown of the other unit.

BASES

BACKGROUND (continued)

Additional information on the design and operation of the system, along with a list of components served, can be found in UFSAR, Section 9.2.5 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on Residual Heat Removal (RHR) operation as well as the sink for heat removed from containment via the reactor containment fan coolers. The UHS performance requirements are that the design basis temperatures of safety related equipment served by SX, either directly or indirectly are not exceeded. The UHS maximum post accident heat load occurs near the time the unit switches from injection to recirculation and the containment cooling systems and residual heat removal systems are required to remove core decay heat. The status of both units must be considered in the UHS analyses, because the UHS is a common system. The design basis accident analyses for the UHS is based on design basis LOCA/loss of offsite power conditions on one unit concurrent with the safe shutdown from maximum power of the other unit. References 2, 3, and 6 provide details of the UHS design basis analyses. The analyses include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single failures.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The UHS maximum basin design temperature is 100°F. To ensure this limit is not exceeded, the SX Cooling Tower (SXCT) fan requirements vary with increasing SX pump discharge water temperature. These requirements involve an increasing number of required SXCT fans to be OPERABLE and whether those fans are required to be running in high speed. The design analysis for determining these requirements was based on the worst-case three-hour outside air wet bulb temperature of 82°F. For example, with SX trains cross tied on both units, if SX pump discharge water temperature is < 77°F, then only six of the eight SXCT fans are required to be OPERABLE and none are required to be running in high speed. If the SX pump discharge water temperature is > 91°F and ≤ 96°F, then all eight SXCT fans are required to be OPERABLE and all are required to be running in high speed. Detailed limits are included in the LCO section.

When SXCT fans are required to be running in high speed, the heat transfer is credited immediately following the event because SXCT fans will automatically reenergize with the respective diesel generator output breaker auto-closure. When fans are not required to be running in high speed heat transfer is not credited until operator action opens riser valves and starts the SXCT fans.

The SX pump discharge water temperature limits are based on a design assumption that in the event of a LOCA, under the most severe design basis weather conditions, and a single breaker failure results in the loss of two SXCT fans, the Operators will shed heat load by securing up to two of the four Reactor Containment Fan Coolers (RCFCs) on the LOCA unit within 21.6 minutes. Only one of the two trains of RCFCs is required to operate for post accident containment heat removal. Also, Operators on the non-accident unit will have to monitor and manage the cooldown rate such that SX discharge temperature limits are not exceeded.

The safety analysis evaluated conditions when two SXCT fans are inoperable on the same electrical division. In this scenario, a postulated breaker failure associated with the power to the other two SXCT fans in the same tower could result in a configuration with no SXCT fans available on one tower and four OPERABLE SXCT fans on the second tower. In this configuration, the overall SXCT performance is less than when SXCT fans are available on both towers. To support design basis accident heat removal in this configuration the outside air wet bulb temperature must be ≤ 76°F.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analyses assume an initial basin level of ≥ 60% in both cooling tower basins, which corresponds to approximately 306,000 gallons in each basin. The analyses consider the AF System requirements, whose safety related source of water is the SX System.

The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 4), which requires a 30 day supply of cooling water in the UHS. The UHS requires makeup to the basins to meet this requirement. The safety related source of makeup is the two diesel driven SX makeup pumps which take suction from the Rock River. The diesel driven SX makeup pumps auto start on low level in their associated tower basin. The SX makeup system is designed to withstand all design basis natural phenomena events and combination of events except for seismic events during low Rock River flow or level (loss of SX makeup pump suction), tornado, and river flood. Therefore, constraints on river level and flow are imposed, and if the weather is conducive to tornadoes or high river levels, plant procedures dictate proactive actions.

A backup makeup source is provided by deep well pumps. The deep well system is designed for seismic, tornado, and river flood events. Each deep well pump is powered from the engineered safety feature bus for the associated tower. The deep well pumps do not include automatic start capability. To compensate for the possible time delay in providing makeup associated with a manual start of the deep well pumps, the minimum acceptable volume of water maintained in each basin is raised (90% level) and the level is verified every 2 hours.

The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it has available a sufficient volume of water at or below the maximum temperature that would allow the SX System to operate for at least 30 days following the design basis event without the loss of Net Positive Suction Head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SX System.

To meet the SX supply design temperature under postulated accident conditions a minimum number of SXCT fans are required to be OPERABLE to remove the postulated accident heat load. The number of SXCT fans required is dependent on

BASES

LCO (continued)

whether SX is operated with SX trains on both units crosstied or SX trains or either unit split. Split train operation is defined as both the supply and the return sides of an SX train are separated from the other SX train. Crosstied train operations is defined as either or both the supply and the return sides of an SX train are not separated from the other SX train, Table 3.7.9-1 contains the SXCT fan requirements corresponding to the SX pump discharge water temperature regions when SX trains on both units are crosstied, and Table 3.7.9-2 contains the SXCT fan requirements corresponding to the SX pump discharge water temperature regions when SX trains are split on either unit.

A SXCT fan is considered OPERABLE when it has a structurally sound cooling cell, a water distribution system, and the capability of running in high speed for 30 days. The number and configuration of SXCT fan requirements vary with increasing SX pump discharge water temperature.

Table 3.7.9-1 is modified by a Note indicating when outside air wet bulb temperature is > 76°F, then each electrical division (i.e., Divisions 11, 12, 21 and 22) must be capable of providing power to at least one OPERABLE SXCT fan.

Two diesel powered SX makeup pumps must also be OPERABLE. SX makeup pump OPERABILITY includes, auto start capability on low basin level, and sufficient river level (> 664.7 ft Mean Sea Level (MSL)) and flow combinations.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

A.1

If there is less than the number of SXCT fans running in required high speed as required by Table 3.7.9-1 or Table 3.7.9-2, then actions must be initiated to operate all the required OPERABLE SXCT fans in high speed. This action ensures the 100°F design temperature limit will not be

ACTIONS (continued)

exceeded during a design basis accident. The immediate Completion Time is reasonable since an OPERABLE SXCT fan must be capable of running in high speed and the fan can be placed in this condition from the Main Control Room.

B.1 and B.2

If one required SXCT fan is inoperable, action must be taken to restore the inoperable SXCT fan to OPERABLE status within 72 hours. Required Action B.1 requires the remaining required OPERABLE SXCT fans be capable of being powered by an OPERABLE emergency power source. This action assures availability of electric power to the remaining required fans in the unlikely event of a loss of offsite power. The 1 hour Completion Time is reasonable based on the fact this is an administrative check of the OPERABILITY of the emergency power sources.

The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hours that one required SXCT fan is inoperable, the number of available systems, and the time required to reasonably complete the Required Action.

C.1 and C.2

These Required Actions are applicable when SX is operating in a crosstied configuration on both Units. When outside air wet bulb temperature is > 76°F and any electrical division is not capable of providing power to at least one SXCT fan, then a postulated worst case single failure could result in no OPERABLE SXCT fans on one tower and four SXCT fans on the second tower. In this potential configuration, design basis SX temperatures could be exceeded. The Required Action is to reconfigure the SXCT fans to eliminate this vulnerability. Required Action C.1 requires the OPERABLE SXCT fans to be capable of being powered by an OPERABLE emergency power source. This action assures availability of electrical power to the SXCT fans in the unlikely event of a loss of offsite power.

The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hour timeframe in addition to a single failure disabling two SXCT fans on the same tower that initially had two inoperable fans.

BASES

ACTIONS (continued)

D.1 and D.2

If the SX pump discharge temperature exceeds 96°F, then the UHS SXCT fans cannot prevent the design SX system temperature limit of 100°F from being exceeded during a design basis accident. Consequently, in this condition, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 3 within 6 hours and in MODE 5 within 36 hours.

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

E.1

If one or more cooling tower basin level is < 60%, the assumptions of the design basis analyses are not met, and action must be taken to restore both basin levels within 6 hours. The 6 hour Completion Time is reasonable based on the low probability of an accident occurring during the 6 hours that the basin level is < 60%, the number of systems available to replenish basin level, and the time required to reasonably complete the Required Actions.

F.1, F.2, and F.3

When one SX makeup pump is inoperable, action must be taken to verify a ≥ 90% cooling tower basin level in both basins within 72 hours, and verify OPERABILITY of an associated makeup source within 72 hours. The increased basin level must be verified every 2 hours thereafter, and the inoperable SX makeup pump must be restored to OPERABLE status within 7 days or 14 days depending on plant conditions.

In this Condition, the remaining OPERABLE makeup sources are adequate to perform the UHS makeup function. However, the overall reliability is reduced because failure of the OPERABLE makeup source(s) could result in a loss of the makeup function.

Required Action F.1 requires verification that both basin levels are ≥ 90%, and Required Action F.2 verifies the OPERABILITY of an associated makeup source (pump and flow path). The increased basin level and its verification every

BASES

ACTIONS (continued)

2 hours provide assurance of enough inventory in the basins to allow sufficient time to manually start makeup sources, consistent with the assumptions of the design basis analyses. An associated makeup source is a source (i.e., ESF powered deep well pump of the same train or the SX makeup pump capable of manual start) which provides makeup to the same basin served by the inoperable SX makeup pump. An SX makeup pump that is inoperable due solely to the inability to auto start on low basin level may be considered an OPERABLE associated makeup source. OPERABILITY of the same train deep well pump includes capability to start and provide sufficient flow to the associated basin.

The 72 hours to verify ≥ 90% basin level and OPERABILITY of an associated makeup source is reasonable based on the low probability of a design basis accident occurring during this time period and the ability of the remaining SX makeup pump to perform the required makeup function. The 2 hour periodic verification of ≥ 90% basin level is consistent with the assumptions of the design basis analyses.

Required Action F.3 requires the SX makeup pump to be restored to OPERABLE status within 7 days or 14 days respectively. The 7 day limit is applicable if both Unit 1 and Unit 2 are in MODE 1, 2, 3, or 4. The 14 day limit is only applicable if either Unit 1 or Unit 2 is in MODE 5, MODE 6, or defueled. This Required Action serves to provide up to 7 days to restore a SX makeup pump when both units are operating, and up to 14 days when one unit is operating and the other is shutdown. The 14 day allowance provides adequate time to perform pump inspection and extended maintenance when one unit is in an outage. Without this allowance, a dual-unit outage would be required to perform maintenance that requires more than 7 days to complete. The extended Completion Time when one unit is in shutdown is also based on the reduction in the quantity of heat that would have to be removed by the UHS when one unit is in a shutdown condition, a reduction in the amount of water that may be required to satisfy AF demands, and the availability of the other makeup water sources. Although the 14 day Completion Time was justified based on the need to perform extended maintenance, its use and application is not restricted to these activities because the effects of SX makeup pump inoperability are unrelated to the cause of the inoperability.

BASES

ACTIONS (continued)

G.1, G.2, and G.3

When both SX makeup pumps are inoperable, action must be taken to verify a ≥ 90% cooling tower basin level in both basins within 1 hour, verify OPERABILITY of at least one makeup source (pump and flow path) within 1 hour, and verify OPERABILITY of a second makeup source serving the other tower basin within 72 hours. The increased basin level must be verified every 2 hours thereafter.

In this Condition, the UHS makeup function may not be met. Required Actions G.1 and G.2 require verification of the OPERABILITY of at least one makeup source and verification that both basin levels are ≥ 90%. The increased basin level and its verification every 2 hours allows sufficient time to manually start makeup sources, consistent with the assumptions of the design basis analyses. An SX makeup pump which is inoperable solely due to the inability to auto start on low basin level may be considered an OPERABLE makeup source. The 1 hour Completion Time is reasonable based on the low probability of an accident occurring during the 1 hour and the time required to reasonably complete the Required Actions.

Required Action G.3 requires verification of the OPERABILITY of a second makeup source within 72 hour. With the plant only having one OPERABLE makeup source, the UHS makeup function can be performed; however the overall reliability is reduced. The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during this time period and the available makeup capability.

BASES

ACTIONS (continued)

H.1

With the Rock River water level ≤ 670.6 ft Mean Sea Level (MSL), action must be taken to assure that adequate level and flow remain available from the Rock River intake to the SX makeup pumps to permit their operation. When the water level in the river falls below this limit, within one hour, and every 12 hours thereafter, the water level in the river must be verified to be greater than 664.7 ft MSL and the flow rate in the river must be verified to be greater than or equal to 700 cubic feet per second (CFS). 700 cfs assures adequate inventory is available for the pumps to maintain the level in the UHS basins. 664.7 ft is the minimum design operating level of the SX makeup pumps. Assuring adequate inventory and a level greater than the minimum operating level provides assurance that the pumps can perform their function if required. The 1 hour Completion Time for initial performance of this Required Action is reasonable based on the low probability of an accident occurring during the 1 hour and the time required to reasonably complete the Required Actions. The continued performance of this verification every 12 hours is reasonable based on the availability of other makeup sources and the low likelihood of an accident and a rapid unexpected decrease in the river level.

BASES

ACTIONS (continued)

I.1, I.2, and I.3

The SX makeup pumps provide the safety-related makeup capability to the UHS, however when Condition I applies, the pumps may not be capable of performing the required function. With water level or flow in the Rock River outside of the limits specified, the pumps may not have adequate NPSH or inventory to supply the required makeup to the UHS if an accident occurs. If water level is forecast by the National Weather Service (NWS) to exceed 698.68 ft MSL on the Rock River at Byron U.S. Geological Survey (USGS) gage location, the SX makeup pumps may be subjected to flooding that would render them inoperable. Similarly, if a Tornado Watch exists that includes the Byron site, the pumps may not be capable of performing their required function because the river screen house that contains the pumps is not designed to protect them from a tornado.

In these conditions, alternative makeup capability to the UHS must be available and the inventory in the UHS basin must be large enough to permit manual initiation of the alternative source. The deep well pumps supply the alternative makeup capability to the UHS. To assure adequate inventory in the UHS to permit a delay in makeup for manual initiation of the deep well pumps, the level in each tower basin must be verified to be greater than or equal to 90% within 1 hour, and every 2 hours thereafter. The 1 hour Completion Time for initial performance of this Required Action is reasonable based on the low probability of an accident occurring during the 1 hour and the time required to reasonably complete the Required Actions. The continued performance of this verification every 2 hours is reasonable based on the low likelihood of an accident and the maximum expected decrease in level in the UHS basin.

In addition, at least one deep well pump must be verified OPERABLE within 1 hour. This assures that if an accident occurs, adequate makeup capability to the UHS is available. The 1 hour Completion Time for initial performance of this Required Action is reasonable based on the low probability of an accident occurring during the 1 hour and the time required to reasonably complete the Required Actions.

BASES

ACTIONS (continued)

Within 72 hours, both deep well pumps must be verified to be OPERABLE if Condition I continues to apply. This Required Action is consistent with the need to assure reliable and redundant supplies are available to provide makeup to the UHS. The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hours coincident with a failure of the OPERABLE deep well pump.

J.1 and J.2

If the UHS cannot be restored to OPERABLE status within the associated Completion Times or the associated Required Actions are not met of Condition A, B, C, E, F, G, or I, or if the UHS is inoperable for reasons other than Condition A, B, C, D, E, F, G, H, or I, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies adequate basin level to provide time to manually establish makeup while providing auxiliary feedwater if required. The specified level also ensures that sufficient NPSH is available to operate the SX pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR verifies that the UHS cooling tower basin water level is ≥ 60%.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2

This SR verifies that the UHS is capable of supporting the SX System. In turn, availability of the UHS ensures the ability of the SX System to cool the CC System to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident and cool the other components served directly by the SX System. This SR specifically verifies that the SX pump discharge water temperature, SXCT fan OPERABILITY, and operational mode is in accordance with the LCO. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.3

This SR verifies the SX makeup pumps are OPERABLE by ensuring river water level and flow are sufficient for proper operation of the SX makeup pumps in case of the Design Basis Accident (DBA). If the river water level is > 670.6 ft MSL and ≤ 698.68 ft MSL, proper operation is assured. If the water level is > 698.68 ft MSL, the pumps may become flooded and not be available. If the river level is ≤ 670.6 ft MSL, proper operation of the pumps during a DBA is possible. However, the river level must be > 664.7 ft MSL and river flow must be ≥ 700 cfs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.4

Starting from the control room and operating each required SXCT fan on high speed for ≥ 15 minutes (if not already operating in high speed) ensures that all SXCT fans are OPERABLE and that all associated controls are functioning properly. It also ensures that fan or motor failure, or excessive vibration, can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.5

Verifying the correct alignment for manual, power operated, and automatic valves in the SX makeup flow path provides assurance that the proper flow paths exist for SX makeup operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.6

This SR verifies that each SX makeup pump starts and operates on an actual or simulated low basin level signal for $\geq$ 30 minutes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.7

This SR provides verification that the level of fuel oil in the day tank is at or above the level that provides approximately a 3 day supply of fuel for the pumps. This is enough time to arrange for addition of more fuel if needed. The level is expressed as a percent of the usable volume of the tank. The 47% indicated level ensures that there is at least 864 gallons of usable fuel to each diesel powered essential service water makeup pump, with an allowance for instrumentation tolerances.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.8

This SR requires that each testable valve in the SX makeup system flow path be cycled through at least one complete cycle of travel. This SR applies to the flow path from the SX makeup pumps to the UHS basins. The SR provides assurance that if a flow path is required, it can be aligned properly.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.9

The tests of fuel oil are a means of assuring it has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. The tests, limits, and applicable ASTM Standards are listed in the Diesel Fuel Oil Testing Program in Specification 5.5.13.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D5452 (Ref. 5). This method involves a determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

Fuel Oil to the Essential Service Water Makeup Pump Day Tanks is supplied from the outside fuel oil storage tanks. These tanks are also subject to the requirements of the Diesel Fuel Oil Testing Program, as described in Specification 5.5.13.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.10

This SR verifies the outside air wet bulb temperature is ≤ 76°F. The SR is modified by a Note indicating that the SR is only required to be performed when any electrical division is not capable of providing power to at least one OPERABLE SXCT fan. If there are two inoperable SXCT fans, both of which are powered by the same electrical division, and the outside air wet bulb temperature exceeds 76°F, then a single failure could make all SXCT cells inoperable on one tower. In this potential configuration, the outside air wet bulb temperature must be restricted to being ≤ 76°F in order to keep from exceeding the design SX system temperature of 100°F. The 12 hour Frequency is reasonable based on the expected outside air wet bulb temperature during the seasonal timeframes this configuration would be intentionally entered for maintenance activities. However, should this configuration occur during seasonal conditions where outside air wet bulb temperature may exceed 76°F, then monitoring intervals should take into account the proximity to the limit and forecasted conditions.

REFERENCES

1. UFSAR, Section 9.2.5.
2. Commonwealth Edison letter to Dr. Thomas E Murley dated January 9, 1992.
3. Commonwealth Edison letter to Dr. Thomas E Murley dated March 31, 1992.
4. Regulatory Guide 1.27.
5. ASTM Standards, D5452.
6. Commonwealth Edison letter to USNRC Document Control Desk dated May 6, 1997.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Ventilation (VC) Filtration System

BASES

BACKGROUND

The common control room filtration and temperature control are provided by the Control Room Ventilation (VC) System. The common VC System consists of two redundant and independent trains. Each train consists of a makeup air filter unit, makeup air fan, supply fan, return fan, supply filter unit, recirculation charcoal absorber, comfort heating coils (not required for OPERABILITY), chiller, chilled water pump and cooling coils. Ductwork, dampers, doors, barriers, and instrumentation also form part of the system.

The makeup air filter unit includes a moisture separator (not required for system OPERABILITY), heater, prefilter (not required for system OPERABILITY), High Efficiency Particulate Air (HEPA) filter, charcoal absorber section for removal of gaseous activity (principally iodines), and second HEPA filter. The moisture separator removes any entrained water. The prefilter removes any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The VC System operation maintains the control room temperature within limits and habitable as discussed in UFSAR, Section 6.4 (Ref. 1) and Section 9.4 (Ref. 2). The VC System (with the exception of the comfort heating coils and humidifier) is designed in accordance with Seismic Category I requirements. The VC System is an emergency system of which parts operate during normal operation. Normally, the supply and return fans of one train are in service with the recirculation charcoal absorber bypassed. The makeup air filter unit and fan are not in service.

The filtration system portion of the VC System (VC Filtration System) provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke. The VC Filtration System recirculates and filters the air in the control room envelope (CRE). The CRE boundary limits the inleakage of unfiltered air.

BASES

BACKGROUND (continued)

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room and other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

Actuation of the VC Filtration System places the system in the emergency mode of operation. Actuation of the system to the emergency mode of operation; starts the makeup fan, opens the turbine building intake damper, isolates the normal intake from outside dampers, isolates the purge dampers (if open), opens the recirculation charcoal absorber dampers, and closes the recirculation charcoal absorber bypass dampers. For an event involving a high energy line break that pressurizes the Turbine Building and results in a Safety Injection (SI) Signal, actuation of the emergency mode of operation; starts the makeup fan, opens the alternate emergency makeup intake from outside damper, isolates the normal intake from outside dampers, isolates the purge dampers (if open), opens the recirculation charcoal absorber dampers, and closes the recirculation charcoal absorber bypass dampers. The operating supply and return fans continue to operate. Interlocks are provided such that the makeup fan will not start unless the associated supply fan is in operation. Outside air is filtered and then mixed with the air being recirculated through the CRE. Pressurization of the CRE minimizes infiltration of unfiltered air through the CRE boundary from all the areas adjacent to the CRE boundary.

The air entering the CRE is continuously monitored by radiation detectors. One outside air intake detector output above the alarm setpoint will cause actuation of the emergency mode of operation and trip the Control Room Offices HVAC (VV) System.

BASES

BACKGROUND (continued)

The VC Filtration System will not automatically realign to the Turbine Building makeup air intake upon receipt of a high radiation or Safety Injection (SI) signal when a VC Filtration System Emergency Makeup Filter unit is in operation and aligned to the outside air intake.

A single VC Filtration System train operating at a makeup flow rate ≥ 5400 cfm and ≤ 6600 cfm will pressurize the CRE relative to external areas adjacent to the CRE boundary.

The control room and the CRE are defined in UFSAR Section 6.4 (Ref. 1). The control room is contained within the CRE. The areas within the CRE, external to the control room, are maintained at a positive pressure.

Redundant filter trains are provided such that if an excessive pressure drop develops across one filter train, the other train is available to provide the required filtration.

The normally open intake isolation dampers are arranged in a series so that the failure of one damper to shut will not result in a breach of isolation. The VC Filtration System is designed in accordance with Seismic Category I requirements.

The VC Filtration System is designed to maintain a habitable environment in the CRE for 30 days after a Design Basis Accident (DBA) without exceeding the total effective dose equivalent (TEDE) limits of 10 CFR 50.67 (Ref. 7), (i.e., 5 rem TEDE).

APPLICABLE SAFETY ANALYSES

The VC System components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The VC Filtration System provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis accident fission product release presented in the UFSAR, Chapter 15 (Ref. 3). The safety analyses assume a 95% filter efficiency for the makeup charcoal absorber and a 90% filter efficiency for the recirculation charcoal absorber. For design basis accident radiological dose assessments, the VC Filtration System is assumed to be initiated within 30 minutes.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The VC Filtration System provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 4). The evaluation of a smoke challenge demonstrates that it will not result in the inability of the operators to control the reactor either from the control room or from the remote shutdown panels (Ref. 2).

The worst case single active failure of a component of the VC Filtration System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The VC Filtration System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii)

LCO

Two independent and redundant VC Filtration System trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a TEDE dose of 5 rem TEDE to the CRE occupants in the event of a large radioactive release.

Each VC Filtration System train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A VC Filtration System train is OPERABLE when the associated:

a. Makeup air fan is OPERABLE;

b. Supply fan is OPERABLE;

c. Return air fan is OPERABLE;

d. HEPA filters and charcoal absorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

e. Makeup filter unit heater, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

BASES

LCO (continued)

In order for the VC Filtration System trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE 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 CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE integrity is required.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of irradiated fuel assemblies, the VC Filtration System must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

In MODE 5 or 6, the VC Filtration System provides protection from significant radioactive releases.

During movement of irradiated fuel assemblies, the VC Filtration System must be OPERABLE to cope with the release from a fuel handling accident involving handling irradiated fuel.

ACTIONS

A.1

When one VC Filtration System train is inoperable, for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE VC Filtration System train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE VC Filtration System train could result in loss of VC Filtration System function. The 7 day

BASES

ACTIONS (continued)

Completion 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.

B.1, B.2, and B.3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE 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 CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE 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 CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion 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 Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE 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 Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

BASES

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable VC Filtration System train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 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.

D.1.1, D.1.2, D.2.1, and D.2.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, if the inoperable VC Filtration System train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE VC Filtration System train in the emergency mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected. Action D.1.2 requires the VC Filtration System train placed in operation be capable of being powered by an OPERABLE emergency power source. This action assures availability of electric power in the unlikely event of a loss of offsite power. This power source can be either from Unit 1 or Unit 2, via OPERABLE crosstie breakers.

An alternative to Required Action D.1.1 and D.1.2 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

E.1 and E.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two VC Filtration System trains inoperable, or with one or more VC Filtration System trains inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

BASES

ACTIONS (continued)

F.1

If both VC Filtration System trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable CRE boundary (i.e., Condition B), the VC Filtration System may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. Operation with the heaters on for ≥ 15 continuous minutes demonstrates OPERABILITY of the system. Periodic operation ensures that heater failure, blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The recirculation subsystem filters do not contain heaters and need only be operated for ≥ 15 minutes to demonstrate the function of the system. For purposes of satisfying this SR, the recirculation subsystem may be run concurrently with the makeup subsystem. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.2

This SR verifies that the required VC Filtration System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VC Filtration System filter tests are in general conformance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing the performance of the HEPA filter, charcoal absorber efficiency, system flow rates, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP. The acceptance criteria stated in the VFTP, ensure that the filter efficiencies assumed in the safety analyses are met.

SR 3.7.10.3

This SR verifies that each VC Filtration System train aligns, starts, and operates on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE 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, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE 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. 9) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 6). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 8). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE 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 CRE boundary has been restored to OPERABLE status.

BASES

REFERENCES

1. UFSAR, Section 6.4.
2. UFSAR, Section 9.4.
3. UFSAR, Chapter 15.
4. UFSAR, Section 2.2.
5. Regulatory Guide 1.52, Rev. 2.
6. NEI 99-03, “Control Room Habitability Assessment Guidance,” June 2001
7. 10 CFR 50.67
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).
9. Regulatory Guide 1.196

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Ventilation (VC) Temperature Control System

BASES

BACKGROUND	The temperature control system portion of the VC System (VC Temperature Control System) provides temperature control for the control room normally and following isolation of the control room. A description of the VC System is provided in the Bases for LCO 3.7.10, "Control Room Ventilation (VC) Filtration System." The VC Temperature Control System consists of the VC components (arranged in two independent and redundant trains) that provide cooling and heating of recirculated control room air. Each train consists of heating coils (not required for System OPERABILITY), a chiller, a chilled water pump, cooling coils, instrumentation, and controls to provide for control room temperature control. The heat load for the chillers is rejected to the Essential Service Water System. A single VC Temperature Control System train will provide the required temperature control to maintain the control room ≤ 90°F.
APPLICABLE SAFETY ANALYSES	The design basis of the VC Temperature Control System is to maintain the control room temperature for 30 days of continuous occupancy. The VC Temperature Control System components are arranged in redundant, safety related trains. During emergency operation, the VC Temperature Control System will maintain the temperature ≤ 90°F. A single active failure of a component of the VC Temperature Control System, with a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The VC Temperature Control System is designed in accordance with Seismic Category I requirements. The VC Temperature Control System is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The VC Temperature Control System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the VC Temperature Control System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The VC Temperature Control System is considered to be OPERABLE when the individual VC components necessary to maintain the control room temperature ≤ 90°F are OPERABLE in both trains. These components include the chillers, chilled water pumps, cooling coils, associated duct work, and associated temperature control instrumentation. In addition, other VC components must be capable of maintaining air circulation.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and at all times during movement of irradiated fuel assemblies in the fuel handling building or containment, the VC Temperature Control System must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

BASES

ACTIONS

A.1

With one VC Temperature Control System train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE VC Temperature Control System train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE VC Temperature Control System train could result in loss of VC Temperature Control System function. The 30 day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and that alternate safety or nonsafety related cooling means are available.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable VC Temperature Control System train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 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 plant systems.

BASES

ACTIONS (continued)

C.1.1, C.1.2, C.2.1, and C.2.2

In MODE 5 or 6, or during movement of irradiated fuel, if the inoperable VC Temperature Control System train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE VC Temperature Control System train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that active failures will be readily detected. Action C.1.2 requires the VC Temperature Control System train placed in operation be capable of being powered by an OPERABLE emergency power source. This action assures availability of electric power in the unlikely event of a loss of offsite power. This power source can be either from Unit 1 or Unit 2, via OPERABLE crosstie breakers.

An alternative to Required Action C.1.1 and C.1.2 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1, D.2 and D.3

With both VC Temperature Control System Trains inoperable, actions must be taken to restore a VC Temperature Control System train to OPERABLE status within 24 hours. During the period that both VC Temperature Control System trains are considered inoperable, action must be initiated immediately to implement mitigating actions (e.g., use of VC System purge mode, use of alternate chilled water sources, or use of supplemental coolers) to lessen potential heat up of the control room.

Control room temperature is required to be monitored to ensure that control room temperature is being controlled. To allow some flexibility in unit operations, the control room temperature limit in Condition D is 80°F, slightly above the normal operating range of the control room. Control room temperature is required to be verified immediately and once per hour thereafter.

BASES

ACTIONS (continued)

With the control room temperature controlled, 24 hours is allowed to restore one VC Temperature Control System train to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained less than or equal to 80°F and the low probability of an event occurring requiring control room isolation.

E.1 and E.2

In MODE 1, 2, 3, or 4, if an inoperable VC Temperature Control System train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. Also, if mitigating actions are not able to ensure control room temperature will be maintained less than or equal to 80°F, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 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 plant systems.

F.1 and F.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies if an inoperable VC Temperature Control System train cannot be restored to OPERABLE status within the required Completion Time, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR monitors the control room temperature for indication of VC Temperature Control System performance. Trending of control room temperature will provide a qualitative assessment of VC Temperature Control System chiller OPERABILITY. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.11.2

This SR verifies that the heat removal capability of the system is sufficient to remove the required heat load. This SR consists of a combination of testing and calculations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

None.

B 3.7 PLANT SYSTEMS

B 3.7.12 Nonaccessible Area Exhaust Filter Plenum Ventilation System

BASES

BACKGROUND

The Nonaccessible Area Exhaust Filter Plenum Ventilation System filters air from the area of the active Emergency Core Cooling System (ECCS) components during the recirculation phase of a Loss Of Coolant Accident (LOCA). The Nonaccessible Area Exhaust Filter Plenum Ventilation System, in conjunction with other normally operating systems, also provides environmental control of temperature in the ECCS pump room area and the lower reaches of the auxiliary building.

The Nonaccessible Area Exhaust Filter Plenum Ventilation System is a subsystem of the common auxiliary building heating, ventilation and air conditioning system (VA). Each unit has two VA supply and two VA exhaust fans. The VA supply and exhaust fans are not required for Nonaccessible Area Exhaust Filter Plenum Ventilation System OPERABILITY.

The Nonaccessible Area Exhaust Filter Plenum Ventilation System consists of three 50% trains. Each train consists of prefilters, High Efficiency Particulate Air (HEPA) filters, activated charcoal adsorber sections for removal of gaseous activity (principally iodines), and two 100% capacity fans. Ductwork, dampers, and instrumentation also form part of the system. A second bank of HEPA filters follows the adsorber sections to collect carbon fines and provide backup in case the main HEPA filter bank fails. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers. Each fan in a train is powered from a different ESF bus. Train A fans are powered by Unit 1 buses 131 and 132; train B fans are powered by Unit 2 buses 231 and 232; and train C fans are powered by Unit 1 bus 132 and Unit 2 bus 231.

BASES

BACKGROUND (continued)

The system is normally aligned with two inlet dampers open and the third train's inlet damper closed. The air passes through the HEPA filters and is routed to the auxiliary building exhaust plenum. The system initiates following receipt of a Safety Injection (SI) signal from either unit. During the emergency mode operation, the auxiliary building normal supply and exhaust fans associated with the unit generating the SI signal are tripped (if operating and there is a concurrent loss of offsite power to that unit). The supply and exhaust fans for the unaffected unit continue to operate or are available if required. The Nonaccessible Area Exhaust Filter Plenum Ventilation System dampers realign, and a fan in each train with an open inlet damper starts to begin filtration. Interlocks are provided; to start the second fan after a time delay in a train if the first fan does not start; to prevent start of a fan in a train with a closed inlet damper; and to prevent start of a fan with a closed discharge damper. The train with the closed inlet damper can be realigned manually from the control room, if required. The Nonaccessible Area Exhaust Filter Plenum Ventilation System emergency mode of operation can also be initiated manually by starting a fan in each train that is aligned for operation. A manual fan start signal will realign the associated dampers to begin filtration.

The Nonaccessible Area Exhaust Filter Plenum Ventilation System is discussed in the UFSAR, Sections 6.5.1, 9.4.5, and 15.6.5 (Refs. 1, 2, and 3, respectively).

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the Nonaccessible Area Exhaust Filter Plenum Ventilation System is established by the large break LOCA. The system evaluation assumes leakage outside containment during the recirculation mode equivalent to two times the maximum permitted recirculation loop leakage consistent with the guidance in Regulatory Guide 1.183 (Ref. 7). In such a case, the system limits radioactive release to within the 10 CFR 50.67 (Ref. 4) limits, or the NRC staff approved licensing basis (e.g., a specified fraction of Reference 5 limits). While the system is automatically initiated on an SI signal, manual actuation/alignment of the system is acceptable. The system is not required until initiation of the ECCS recirculation mode. The analysis of the effects and consequences of a large break LOCA is presented in Reference 3. The Nonaccessible Area Exhaust Filter Plenum Ventilation System also actuates following a small break LOCA, in those cases where the ECCS goes into the recirculation mode of long term cooling, to clean up releases of smaller leaks, such as from valve stem packing. The Nonaccessible Area Exhaust Filter Plenum Ventilation System is also credited in the control room habitability analysis (Ref. 5). The safety analyses assume a 90% filter efficiency.

The Nonaccessible Area Exhaust Filter Plenum Ventilation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The Nonaccessible Area Exhaust Filter Plenum Ventilation System is required to be OPERABLE to ensure that atmospheric releases from the ECCS pump rooms do not exceed those assumed in the safety analysis. Total system failure could result in the atmospheric release, 1) exceeding 10 CFR 50.67 limits in the event of a Design Basis Accident (DBA), and 2) exceeding the limits for control room habitability. The Nonaccessible Area Exhaust Filter Plenum Ventilation System is considered OPERABLE when the individual components, necessary to maintain ECCS pump rooms and equipment rooms filtration are OPERABLE.

In order for the Nonaccessible Area Exhaust Filter Plenum Ventilation System to perform its function, filtration and motive flow must be provided by two of the three trains, the bypass path(s) to the normal auxiliary building exhaust system must be isolated, and the third train's inlet damper must be closed. The closure of the third train's inlet damper, prevents starting of a third fan and also ensures filtration of the exhaust from the ECCS pump rooms, by eliminating potential bypass flow paths.

Three trains of the Nonaccessible Area Exhaust Filter Plenum Ventilation System are required to be OPERABLE to ensure that at least two are available, assuming a single failure coincident with loss of offsite power on the affected unit and an orderly shutdown on the other unit. In addition due to design considerations, two of the trains must be aligned for operation and one train must be aligned in standby (i.e., the inlet damper closed).

To accommodate the single failure and loss of offsite power assumptions, the required fans in each of the Nonaccessible Area Exhaust Filter Plenum Ventilation System trains must be independent of the credited fans in the other trains.

BASES

LCO (continued)

A Nonaccessible Area Exhaust Filter Plenum Ventilation System train is considered OPERABLE when:

a. A charcoal booster fan which is powered from a power supply different than the other two trains is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork and dampers are OPERABLE, and air circulation can be maintained.

The alignment of an Nonaccessible Area Exhaust Filter Plenum Ventilation System train for operation or in standby does not affect the OPERABILITY of the train. For example, alignment of an inoperable train for operation and an OPERABLE train in standby for the purpose of testing the inoperable train, represents a Condition of only one train inoperable.

The LCO is modified by a Note that allows suspension of the requirement to have two trains aligned for operation and one train aligned in standby, intermittently under administrative controls. This allowance is in recognition that for the short time period when a train is realigned for operation from standby and another train is realigned to standby from operation, that more than one damper may be closed or more than two dampers may be opened. These conditions would normally result in the loss of Nonaccessible Area Exhaust Filter Plenum Ventilation System functional capability.

APPLICABILITY

In MODES 1, 2, 3, and 4, the Nonaccessible Area Exhaust Filter Plenum Ventilation System is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODE 5 or 6, the Nonaccessible Area Exhaust Filter Plenum Ventilation System is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

BASES

ACTIONS

A.1

With one Nonaccessible Area Exhaust Filter Plenum Ventilation System train inoperable, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE trains are adequate to perform the Nonaccessible Area Exhaust Filter Plenum Ventilation System function.

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining trains to provide the required capability.

If only two fans are powered from different power supplies, one train should be declared inoperable. Securing closed the inoperable train's inlet damper and assuring the other inlet dampers are open, maintains functional capability of the system.

If more than one inlet damper is inoperable, only one train need be declared inoperable, provided one inoperable damper is secured in the closed position and the other damper(s) are secured in the open position (with its associated fan(s) starting interlock enabled).

If two or more inlet dampers are closed, a single failure of the damper(s) to open would result in the loss of functional capability. Concurrent failure of two or more Nonaccessible Area Exhaust Filter Plenum Ventilation System trains would also result in the loss of functional capability. For any loss of functional capability, LCO 3.0.3 must be entered immediately.

BASES

ACTIONS (continued)

B.1 and B.2

If the Nonaccessible Area Exhaust Filter Plenum Ventilation System train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 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 plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Standby systems should be checked periodically to ensure that they function properly. System operation for ≥ 15 minutes demonstrates the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.2

This SR verifies that the required Nonaccessible Area Exhaust Filter Plenum Ventilation System testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The Nonaccessible Area Exhaust Filter Plenum Ventilation System filter tests are in general conformance with Reference 6. The VFTP includes testing HEPA filter performance, charcoal adsorbers efficiency, system flow rates, and the physical properties of the activated charcoal (general use and following specific operations). Specific test Frequencies and additional information are discussed in detail in the VFTP. The acceptance criteria stated in the VFTP ensure that the filter efficiencies assumed in the safety analyses are met.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.3

This SR verifies that each Nonaccessible Area Exhaust Filter Plenum Ventilation System train aligns, starts, and operates on a manual, an actual, or a simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.4

This SR verifies the integrity of the ECCS pump room areas. The ability of the ECCS pump room areas to maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper functioning of the Nonaccessible Area Exhaust Filter Plenum Ventilation System. During the emergency mode of operation, the Nonaccessible Area Exhaust Filter Plenum Ventilation System is designed to maintain a slight negative pressure in the ECCS pump rooms, with respect to adjacent areas, to prevent unfiltered LEAKAGE. The Nonaccessible Area Exhaust Filter Plenum Ventilation System is designed to maintain a ≤ -0.25 inches water gauge relative to atmospheric pressure with two trains operating, each at a flow rate ≤ 68,200 cubic feet per minute (cfm). Nonaccessible Area Exhaust Filter Plenum Ventilation System function must be maintained considering the design basis scenarios of an SI signal only on one unit or an SI signal concurrent with a loss of offsite power to a unit. This SR should be performed with the postulated number of VA supply and exhaust fans running considering the SI signal only scenario. Performance of the SR in this manner produces the least negative pressure in the ECCS pump room areas (i.e., the least margin to ≤ -0.25 inches water gauge). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

If a particular pump room is isolated such that there is no potential for post accident fluids to pass through the room, or that room's ECCS equipment is not required, that room can be excluded from meeting the acceptance criteria of the SR. Performance of this SR with a room excluded, represents a change in the ECCS pump room area volume that the system is maintaining at a negative pressure. Prior to the room being put back in service, this SR would have to be performed with the new volume, to assure that the system can maintain the entire volume at the required negative pressure.

REFERENCES

1. UFSAR, Section 6.5.1.
2. UFSAR, Section 9.4.5.
3. UFSAR, Section 15.6.5.
4. 10 CFR 50.67.
5. UFSAR, Section 6.4.
6. Regulatory Guide 1.52 (Rev. 2).
7. Regulatory Guide 1.183, July 2000.

BASES

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System

BASES

BACKGROUND

The FHB Ventilation System is available to filter airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. The FHB Ventilation System, in conjunction with other normally operating systems, also provides environmental control of temperature in the fuel pool area.

The FHB Ventilation System is a subsystem of the common auxiliary building heating, ventilation, and air conditioning system (VA). Each unit has two VA supply and two VA exhaust fans. The VA supply and exhaust fans are not required for FHB Ventilation System OPERABILITY.

The FHB Ventilation System consists of two independent and redundant trains. Each 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 or dampers, and instrumentation also form part of the system. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provide backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the analysis, but serves to collect charcoal fines, and to back up the upstream HEPA filter should it develop a leak. The system initiates filtered ventilation of the fuel handling building following receipt of a high radiation signal or a Safety Injection (SI) on either unit.

BASES

BACKGROUND (continued)

The FHB Ventilation System is a standby system. During normal operation flow from the fuel handling building is routed through the FHB Ventilation System prefilters and HEPA filters and then through the VA exhaust plenum via the VA exhaust fans. Upon FHB Ventilation System actuation (emergency mode of operation), the bypass dampers close, and the FHB Ventilation System fans start, drawing air through the FHB Ventilation System charcoal filters. The prefilters remove any large particles in the air to prevent excessive loading of the HEPA filters and charcoal adsorbers. The FHB Ventilation System may also be initiated manually.

The FHB Ventilation System is discussed in the UFSAR, Sections 6.5.1, 9.4.5, and 15.7.4 (Refs. 1, 2, and 3, respectively).

APPLICABLE SAFETY ANALYSES

The FHB Ventilation System design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident involving handling RECENTLY IRRADIATED FUEL. The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged. The DBA analysis of the fuel handling accident assumes that only one train of the FHB Ventilation System is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the one remaining train of this filtration system. The amount of fission products available for release from the fuel handling building is determined for a fuel handling accident. The accident analyses assume a 90% filter efficiency for elemental iodine and a 70% filter efficiency for methyl iodine. Due to radioactive decay, the FHB Ventilation System is only required to isolate during fuel handling accidents involving handling RECENTLY IRRADIATED FUEL. These assumptions and analyses follow the guidance provided in Regulatory Guide 1.183 (Ref. 4).

The FHB Ventilation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Two independent and redundant trains of the FHB Ventilation System are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train, coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the fuel handling building exceeding the 10 CFR 50.67 (Ref. 5) limits in the event of a fuel handling accident involving handling RECENTLY IRRADIATED FUEL.

The FHB Ventilation System is considered OPERABLE when the individual components necessary to control exposure in the fuel handling building are OPERABLE in both trains. An FHB Ventilation System train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

APPLICABILITY

During movement of RECENTLY IRRADIATED FUEL in the fuel handling building, the FHB Ventilation System is required to be OPERABLE to alleviate the consequences of a fuel handling accident.

During movement of RECENTLY IRRADIATED FUEL in the containment with the containment equipment hatch not intact, the FHB Ventilation System is required to be OPERABLE to mitigate the consequences of an accident inside containment. The equipment hatch is considered not intact if both personnel air lock doors associated with the equipment hatch are open or the hatch is not held in place with at least four bolts.

BASES

ACTIONS

The Actions Table is modified by a Note indicating that LCO 3.0.3 does not apply. If moving RECENTLY IRRADIATED FUEL assemblies in the fuel handling building while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving RECENTLY IRRADIATED FUEL assemblies while in MODES 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of RECENTLY IRRADIATED FUEL assemblies is not sufficient to require a reactor shutdown.

A.1

With one FHB Ventilation System train inoperable, action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the FHB Ventilation System function. The 7 day Completion Time is based on the risk from an event occurring requiring the inoperable FHB Ventilation System train, and the remaining FHB Ventilation System train providing the required protection.

B.1.1, B.1.2, B.2.1, and B.2.2

When Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE FHB Ventilation System train must be placed in the emergency mode or RECENTLY IRRADIATED FUEL movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing system operation will occur, and that any active failure will be readily detected. Required Action B.1.2 requires the FHB Ventilation System train placed in operation be capable of being powered by an OPERABLE emergency power source. This action assures availability of electric power in the unlikely event of a loss of offsite power. This power source can be from Unit 1 or Unit 2, via OPERABLE crosstie breakers.

If the system is not placed in the emergency mode, Action B.2.1 requires suspension of RECENTLY IRRADIATED FUEL movement in the fuel handling building, which precludes a fuel handling accident involving handling RECENTLY IRRADIATED FUEL in the fuel handling building. This does not preclude the movement of fuel assemblies to a safe position.

BASES

ACTIONS (continued)

Required Action B.2.2 requires suspension of movement of RECENTLY IRRADIATED FUEL assemblies inside containment, precluding an accident that might require actuation of the FHB Ventilation System (when the equipment hatch is not intact).

Required Action B.2.2 is modified by a Note which indicates that this Required Action is only required if the equipment hatch is not intact. If the hatch is intact, only Required Action B.2.1 is required.

C.1 and C.2

When two trains of the FHB Ventilation System are inoperable action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of RECENTLY IRRADIATED FUEL assemblies in the fuel handling building. This does not preclude the movement of fuel to a safe position.

Required Action C.2 requires suspension of movement of RECENTLY IRRADIATED FUEL assemblies inside containment, precluding an accident that might require actuation of the FHB Ventilation System (when the equipment hatch is not intact).

Required Action C.2 is modified by a Note which indicates that this Required Action is only required if the equipment hatch is not intact. If the hatch is intact, only Required Action C.1 is required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they function properly.

System operation for ≥ 15 minutes demonstrates the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.13.2

This SR verifies that the required FHB Ventilation System testing is performed in general conformance with the Ventilation Filter Testing Program (VFTP). The FHB Ventilation System filter tests are in general conformance with Regulatory Guide 1.52 (Ref. 6). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow rates, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP. The acceptance criteria stated in the VFTP ensure that the filter efficiencies assumed in the safety analyses are met.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.3

This SR verifies the integrity of the fuel handling building and containment enclosure. The ability of the fuel handling building and containment to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FHB Ventilation System and enclosure integrity. During the emergency mode of operation the FHB Ventilation System is designed to maintain a slight negative pressure in the fuel handling building to prevent unfiltered leakage. The FHB Ventilation System is designed to maintain a ≤ -0.25 inches water gauge with respect to atmospheric pressure. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that requires this SR only during movement of RECENTLY IRRADIATED FUEL assemblies (in the fuel building or in the containment) when the equipment hatch is not intact.

SR 3.7.13.4

This SR verifies that each FHB Ventilation System train aligns, starts, and operates on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.5

This SR verifies the integrity of the fuel handling building enclosure. The ability of the fuel handling building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FHB Ventilation System. During the emergency mode of operation the FHB Ventilation System is designed to maintain a slight negative pressure in the fuel handling building, to prevent unfiltered leakage. The FHB Ventilation System is designed to maintain a ≤ -0.25 inches water gauge with respect to atmospheric pressure at a flow rate ≤ 23,100 cfm to the fuel handling building.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that requires this SR only during movement of RECENTLY IRRADIATED FUEL assemblies in the fuel handling building when the equipment hatch is intact.

REFERENCES

1. UFSAR, Section 6.5.1.
2. UFSAR, Section 9.4.5.
3. UFSAR, Section 15.7.4.
4. Regulatory Guide 1.183, July 2000.
5. 10 CFR 50.67.
6. Regulatory Guide 1.52 (Rev. 2).

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pool meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel pool design is given in the UFSAR, Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the UFSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the UFSAR, Section 15.7.4 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the spent fuel pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 4). The resultant Total Effective Dose Equivalent (TEDE) dose is within 10 CFR 50.67 limits (Ref. 5).

According to Reference 4, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool water surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 4 can be used directly. In practice, this LCO preserves the assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the width of the bundle. To offset this small nonconservatism, the analysis assumes that all fuel rods fail, although analysis shows that only the first few rows fail from a hypothetical maximum drop.

The spent fuel pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO	The spent fuel pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required for fuel storage and movement within the spent fuel pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the spent fuel pool, since the potential for a release of fission products exists.
ACTIONS	The ACTIONS have been modified by a Note indicating that LCO 3.0.3 does not apply.

<u>A.1</u>

When the initial conditions assumed in the accident analysis cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel pool water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel pool is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies sufficient spent fuel pool water is available in the event of a fuel handling accident. The water level in the spent fuel pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

During refueling operations, the level in the spent fuel pool is in equilibrium with the refueling cavity when they are hydraulically coupled, and the level in the refueling cavity is checked daily in accordance with SR 3.9.7.1.

REFERENCES

1. UFSAR, Section 9.1.2.

2. UFSAR, Section 9.1.3.

3. UFSAR, Section 15.7.4.

4. Regulatory Guide 1.183, July 2000.

5. 10 CFR 50.67.

BASES (continued)

This page intentionally left blank.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND

The spent fuel pool provides for storage of various Westinghouse Optimized Fuel Assembly (OFA) types of different initial fuel enrichments and exposure histories in two distinct regions. (For this discussion, the term OFA is intended to refer to the specific reduced fuel rodlet diameter, and includes all analyzed fuel types with this diameter, such as Vantage 5.) The 24 spent fuel pool storage racks provide placement locations for a total of 2984 new or used fuel assemblies. Of the 24 spent fuel pool storage racks, four are designated "Region 1" with the remaining 20 racks designated as "Region 2." The analytical methodology used for the criticality analyses is in accordance with established NRC guidelines (Ref. 2).

Region 1 racks contain 396 cells which are analyzed for storing Westinghouse OFAs in an "All Cells" arrangement (that is, the criticality analysis assumes that spent fuel assemblies reside in all available cell locations). The stored fuel assemblies may contain an initial nominal enrichment of ≤ 5.0 weight percent U-235 (with or without IFBAs installed) (Ref. 5).

Region 2 racks contain 2588 cells which are also analyzed for storing Westinghouse OFAs in an "All Cells" arrangement (that is, the criticality analysis assumes that spent fuel assemblies reside in all available cell locations). For the "All Cells" storage configuration, the stored fuel assemblies may contain an initial nominal enrichment of ≤ 5.0 weight percent U-235 with credit for burnup.

The water in the spent fuel pool normally contains soluble boron which results in large subcriticality margins under actual operating conditions.

APPLICABLE SAFETY ANALYSES

NRC approved methodologies were used to develop the criticality analyses (Ref. 2) for the spent fuel pool storage racks. The fuel handling accident analyses are described in Reference 6. Additional evaluations were performed (Ref. 8) to support placement of the Byron lead test assemblies with higher density pellets in the spent fuel pool.

The criticality analyses for the spent fuel assembly storage racks confirm that k_{eff} remains ≤ 0.95 for the spent fuel pool storage racks (including uncertainties and tolerances) at a 95% probability with a 95% confidence level (95/95 basis), based on the accident condition of the pool being flooded with unborated water. Thus, the design of both regions assumes the use of unborated water while maintaining stored fuel in a subcritical condition.

However, the presence of soluble boron has been credited to provide adequate safety margin to maintain spent fuel assembly storage rack k_{eff} ≤ 0.95 (also on a 95/95 basis) for all postulated accident scenarios involving dropped or misloaded fuel assemblies. Crediting the presence of soluble boron for mitigation of these scenarios is acceptable based on applying the "double contingency principle" which states that there is no requirement to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident (Refs. 9 and 10).

The accident analyses address the following five postulated scenarios:

1) fuel assembly drop on top of rack;
2) fuel assembly drop between rack modules;
3) fuel assembly drop between rack modules and spent fuel pool wall;
4) change in spent fuel pool water temperature; and
5) fuel assembly loaded contrary to placement restrictions.

Of these, only scenarios 2, 3, and 5 have the capacity to increase reactivity for the spent fuel pool storage racks.

Calculations were performed, for the spent fuel pool storage racks, for a spent fuel pool temperature of 4°C (39°F) which is well below the lowest normal operating temperature (50°F). Because the temperature coefficient of reactivity in the spent fuel pool is negative, temperatures greater than 4°C will result in a decrease in reactivity.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Calculations were also performed to show the largest reactivity increase caused by a Westinghouse 17X17 OFA fuel assembly misplaced into a Region 2 storage cell for which the restrictions on enrichment or burnup are not satisfied. The assembly misload accident can only occur during fuel handling operations in the spent fuel pool.

For the above postulated accident conditions, the double contingency principle can be applied. Specifically, the presence of soluble boron in the spent fuel pool water can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event. For the spent fuel pool storage racks, spent fuel pool soluble boron has been credited in the criticality safety analysis to offset the reactivity caused by postulated accident conditions. Because the Region 1 racks are designed for the storage of fresh fuel assemblies, a fuel assembly misload accident has no consequences from a criticality standpoint (i.e., the acceptance criteria for storage are satisfied by all assemblies in the spent fuel pool).

Should a fuel assembly misload accident occur in the Region 2 storage cells, k_{eff} will be maintained ≤ 0.95 due to the presence of at least 300 ppm of soluble boron in the spent fuel pool water.

The concentration of dissolved boron in the spent fuel pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	The spent fuel pool boron concentration is required to be ≥ 300 ppm. The specified concentration of dissolved boron in the spent fuel pool preserves the assumptions used in the analyses of the potential critical accident scenarios as described in References 5, 6, and 7. The dissolved boron concentration of 300 ppm bounds the minimum required concentration for accidents occurring during fuel assembly movement within the spent fuel pool.
APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the spent fuel pool.

BASES

ACTIONS

The ACTIONS have been modified by a Note indicating that LCO 3.0.3 does not apply.

A.1 and A.2

When the concentration of boron in the spent fuel pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. This does not preclude movement of a fuel assembly to a safe position. Immediate actions are also taken to restore spent fuel pool boron concentration.

If moving fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies that the concentration of boron in the spent fuel pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. Deleted

2. NRC Memorandum from L. Kopp to T. Collins, "Guidance on the Regulatory Requirements for Criticality Analysis of Fuel Storage at Light Water Reactor Power Plants," dated August 19, 1998.

3. Deleted

4. Deleted

5. Holtec International Report, HI-982094, "Criticality Analysis for the Byron/Braidwood Rack Installation Project," Project No. 80944, 1998.

6. UFSAR, Section 15.7.4.

7. "Byron/Braidwood Spent Fuel Pool Dilution Analysis," Rev. 3, dated June 17, 1997.

8 CN-CRIT-141 "Analysis Supporting the LTA Assemblies for Byron/Braidwood SFP," dated February 4, 1999.

9. Double contingency principle of ANSI N16.1 - 1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

10. ANSI/ANS 8.1 - 1983 "American National Standard for Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors."

11. Safety Evaluation Report (SER) dated October 25, 1996, issued by the Office of Nuclear Reactor Regulation for Topical Report WCAP-14416-NP-A "Westinghouse Spent Fuel Rack Criticality Analysis Methodology."

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Assembly Storage

BASES

BACKGROUND

The spent fuel pool provides for storage of various Westinghouse Optimized Fuel Assembly (OFA) types of different initial fuel enrichments and exposure histories in two distinct regions. (For this discussion, the term OFA is intended to refer to the specific reduced fuel rodlet diameter, and includes all analyzed fuel types with this diameter, such as Vantage 5.) The 24 spent fuel pool storage racks provide placement locations for a total of 2984 new or used fuel assemblies. Of these 24 spent fuel pool storage racks, four are designated "Region 1" with the remaining 20 racks designated as "Region 2." The analytical methodology used for the criticality analyses is in accordance with established NRC guidelines (Ref. 2).

Region 1 racks contain 396 cells which are analyzed for storing Westinghouse OFAs in an "All Cells" arrangement (that is, the criticality analysis assumes that spent fuel assemblies reside in all available cell locations). The stored fuel assemblies may contain an initial nominal enrichment of ≤ 5.0 weight percent U-235 (with or without IFBAs installed) (Ref. 5).

Region 2 racks contain 2588 cells which are also analyzed for storing Westinghouse OFAs in an "All Cells" arrangement (that is, the criticality analysis assumes that spent fuel assemblies reside in all available cell locations). For the "All Cells" storage configuration, the stored fuel assemblies may contain an initial nominal enrichment of ≤ 5.0 weight percent U-235 with credit for burnup.

The water in the spent fuel pool normally contains soluble boron which results in large subcriticality margins under actual operating conditions.

BASES

APPLICABLE SAFETY ANALYSES

NRC approved methodologies were used to develop the criticality analyses (Ref. 2) for the spent fuel pool storage racks. The fuel handling accident analyses are described in Reference 6. Additional evaluations were performed (Ref. 8) to support placement of the Byron lead test assemblies with higher density pellets in the spent fuel pool.

The criticality analyses for the spent fuel assembly storage racks confirm that k_{eff} remains ≤ 0.95 for the spent fuel pool storage racks (including uncertainties and tolerances) at a 95% probability with a 95% confidence level (95/95 basis), based on the accident condition of the pool being flooded with unborated water. Thus, the design of both regions assumes the use of unborated water while maintaining stored fuel in a subcritical condition.

However, the presence of soluble boron has been credited to provide adequate safety margin to maintain spent fuel assembly storage rack k_{eff} ≤ 0.95 (also on a 95/95 basis) for all postulated accident scenarios involving dropped or misloaded fuel assemblies. Crediting the presence of soluble boron for mitigation of these scenarios is acceptable based on applying the "double contingency principle" which states that there is no requirement to assume two unlikely, independent, concurrent events to ensure protection against a criticality accident (Refs. 9 and 10).

The accident analyses address the following five postulated scenarios:

1) fuel assembly drop on top of rack;
2) fuel assembly drop between rack modules;
3) fuel assembly drop between rack modules and spent fuel pool wall;
4) change in spent fuel pool water temperature; and
5) fuel assembly loaded contrary to placement restrictions.

Of these, only scenarios 2, 3, and 5 have the capacity to increase reactivity for the spent fuel pool storage racks.

Calculations were also performed for a spent fuel pool temperature of 4°C (39°F) which is well below the lowest normal operating temperature (50°F). Because the temperature coefficient of reactivity in the spent fuel pool is negative, temperatures greater than 4°C will result in a decrease in reactivity.

BASES

APPLICABLE SAFETY ANALYSES (continued)

For the fuel assembly misload accident, calculations were performed to show the largest reactivity increase caused by a Westinghouse 17X17 OFA fuel assembly misplaced into a Region 2 storage cell for which the restrictions on enrichment or burnup are not satisfied. The assembly misload accident can only occur during fuel handling operations in the spent fuel pool.

For the above postulated accident conditions, the double contingency principle can be applied. Specifically, the presence of soluble boron in the spent fuel pool water can be assumed as a realistic initial condition since not assuming its presence would be a second unlikely event. For the spent fuel pool storage racks, spent fuel pool soluble boron has been credited in the criticality safety analysis to offset the reactivity caused by postulated accident conditions. Because the Region 1 racks are designed for the storage of fresh fuel assemblies, a fuel assembly misload accident has no consequences from a criticality standpoint (i.e., the acceptance criteria for storage are satisfied by all assemblies in the spent fuel pool).

Should a fuel assembly misload accident occur in the Region 2 storage cells, k_{eff} will be maintained ≤ 0.95 due to the presence of at least 300 ppm of soluble boron in the spent fuel pool water.

The configuration of fuel assemblies in the spent fuel pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool in accordance with the requirements in the accompanying LCO ensure that the k_{eff} of the spent fuel pool will always remain ≤ 0.95 assuming the pool is flooded with unborated water for the spent fuel pool storage racks. For the spent fuel pool storage racks, in LCO Figure 3.7.16-1, the Acceptable Burnup Domain lies on, above, and to the left of the line. The use of linear interpolation between minimum burnups is acceptable.
APPLICABILITY	This LCO applies whenever fuel assemblies are stored in the spent fuel pool.

BASES

ACTIONS

The ACTIONS have been modified by a Note indicating that LCO 3.0.3 does not apply.

A.1

When the configuration of fuel assemblies stored in the spent fuel pool is not in accordance with the requirements of the LCO, immediate action must be taken to make the necessary fuel assembly movement(s) to bring the configuration into compliance.

If moving fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

Item a and item b are performed, as applicable, is performed prior to storing the fuel assembly in the intended spent fuel pool storage location. The frequency is appropriate because compliance with the SR ensures that the relationship between the fuel assembly and its storage location will meet the requirements of the LCO and preserve the assumptions of the analyses.

This SR verifies by administrative means that the initial nominal enrichment of the fuel assembly is met to ensure that the assumptions of the safety analyses are preserved.

SR 3.7.16.2

SR 3.7.16.2 is performed prior to storing the fuel assembly in the intended spent fuel pool storage location. The frequency is appropriate because compliance with the SR ensures that the relationship between the fuel assembly and its storage location will meet the requirements of the LCO and preserve the assumptions of the analyses.

This SR verifies by administrative means that the combination of initial enrichment, burnup, and decay time, as applicable, of the fuel assembly is within the Acceptable Burnup Domain of Figure 3.7.16-1 for the intended storage configuration to ensure that the assumptions of the safety analyses are preserved.

BASES

REFERENCES

1. Deleted

2. NRC Memorandum from L. Kopp to T. Collins, "Guidance on the Regulatory Requirements for Criticality Analysis of Fuel Storage at Light Water Reactor Power Plants," dated August 19, 1998.

3. Deleted

4. Deleted

5. Holtec International Report, HI-982094, "Criticality Analysis for the Byron/Braidwood Rack Installation Project," Project No. 80944, 1998.

6. UFSAR, Section 15.7.4.

7. "Byron/Braidwood Spent Fuel Pool Dilution Analysis," Rev. 3, dated June 17, 1997.

8 CN-CRIT-141 "Analysis Supporting the LTA Assemblies for Byron/Braidwood SFP," dated February 4, 1999.

9. Double contingency principle of ANSI N16.1 - 1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

10. ANSI/ANS 8.1 - 1983 "American National Standard for Nuclear Criticality Safety in Operations with Fissionable Materials Outside Reactors."

11. Safety Evaluation Report (SER) dated October 25, 1996, issued by the Office of Nuclear Reactor Regulation for Topical Report WCAP-14416-NP-A "Westinghouse Spent Fuel Rack Criticality Analysis Methodology."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (Train A and Train B Diesel Generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (divisions) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each division has connections to two offsite power sources and a single DG.

Offsite power is supplied to the station switchyard from the transmission network. From the switchyard, two electrically and physically separated lines (i.e., independent transmission circuits) provide AC power through their associated System Auxiliary Transformer (SAT) banks (SATs 142-1 and 142-2 from one line, and SATs 242-1 and 242-2 from the second line), to the 4.16 kV ESF buses. Normally, SATs 142-1 and 142-2 feed Unit 1 4.16 kV ESF buses, and SATs 242-1 and 242-2 feed Unit 2 4.16 kV ESF buses. Additionally, each 4.16 kV ESF bus has a reserve feed via its associated crosstie to an opposite-unit 4.16 kV ESF bus. Each unit is required to have qualified normal and reserve circuits to each 4.16 kV bus (detailed in the LCO Bases for this Specification). The transmission network and switchyard are maintained in accordance with UFSAR, and are not governed by the requirements of Technical Specifications. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

BACKGROUND (continued)

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs 1A (2A) and 1B (2B) are dedicated to ESF buses 141 (241) and 142 (242), respectively. A DG starts automatically on a Safety Injection (SI) signal (i.e., manual SI, low steam line pressure, low pressurizer pressure or high-1 containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by automatic load sequencing. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of offsite power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a Loss Of Coolant Accident (LOCA).

Certain required unit loads are automatically connected to the DGs in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are automatically connected to the DGs.

Continuous service ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 5500 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the plant. This results in maintaining at least one division of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power sources; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits per 4.16 kV bus between the offsite transmission network and the onsite Class 1E Electrical Power System and separate and independent DGs for each division ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an Anticipated Operational Occurrence (AOO) or a postulated DBA.

Qualified circuits are those that are described in the UFSAR and are part of the licensing basis for the plant.

Each qualified circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

BASES

LCO (continued)

For Unit 1 (Unit 2), the two qualified circuits (a normal circuit and a reserve circuit) per ESF bus between the offsite transmission network and the onsite 4.16 kV ESF buses are as follows:

a. NORMAL

ESF bus 141 (241)	345 kV system through system auxiliary transformer (SAT) 142-1 (242-1) or by use of disconnect links via SAT 142-2 (242-2); and
ESF bus 142 (242)	345 kV system through SAT 142-2 (242-2) or by use of disconnect links via SAT 142-1 (242-1); and

b. RESERVE

ESF bus 141 (241)	345 kV system through SAT 242-1 (142-1) or by use of disconnect links via SAT 242-2 (142-2), to 4.16 kV ESF bus 241 (141) crosstied to 4.16 kV ESF bus 141 (241); and
ESF bus 142 (242)	345 kV system through SAT 242-2 (142-2) or by use of disconnect links via SAT 242-1 (142-1), to 4.16 kV ESF bus 242 (142) crosstied to 4.16 kV ESF bus 142 (242).

A standby (onsite) source to the 4.16 kV ESF buses is provided by DG 1A (2A) for 4.16 kV ESF bus 141 (241) and DG 1B (2B) for 4.16 kV ESF bus 142 (242).

BASES

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG engine hot and DG engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances (e.g., capability of the DG to revert to standby status on an Emergency Core Cooling System (ECCS) signal while operating in parallel test mode).

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division. For the DGs, separation and independence are complete. For the qualified circuits, separation and independence are to the extent practical.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources-Shutdown."

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one required qualified circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required qualified circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if another required circuit fails SR 3.8.1.1, this qualified circuit is inoperable, and additional Conditions and Required Actions may be appropriate. If the additional inoperability results in a bus with two required qualified circuits inoperable Condition D is entered. If the additional inoperability results in the second bus with one required qualified circuit inoperable Condition A is still applicable.

A.2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With one or more buses with one required qualified circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this Condition, however, the remaining OPERABLE required qualified circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1

The 14 day Completion Time for Required Action B.5 is predicated on the OPERABILITY of the opposite-unit DGs (Ref. 7). It is required to verify both opposite-unit DGs OPERABLE within 1 hour and to continue this action once per 24 hours thereafter until restoration of the required DG is accomplished. This verification provides assurance that both opposite-unit DGs are capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

BASES

ACTIONS (continued)

B.2

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the required qualified circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a required qualified circuit fails to pass SR 3.8.1.1, it is inoperable, and additional Conditions and Required Actions apply.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features (i.e., systems, subsystems, trains, components, and devices) are designed with redundant safety related trains. This includes the diesel driven auxiliary feedwater pump. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

BASES

ACTIONS (continued)

Discovering one required DG inoperable coincident with one or more inoperable required redundant feature(s) results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.4.1 and B.4.2

Required Action B.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition F of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

BASES

ACTIONS (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the Corrective Action Program Procedure will continue to evaluate the common cause possibility and determine the need for any additional DG testing. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

If while a DG is inoperable, a new problem with the DG is discovered that would have prevented the DG from performing its specified safety function, a separate entry into Condition B is not required. The new DG problem should be addressed in accordance with the Corrective Action Program.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

B.5

According to Reference 7, operation may continue in Condition B for a period that should not exceed 14 days. This Completion Time is based upon a risk-informed assessment that concluded that the associated risk is acceptable based upon the availability of the offsite power sources and the onsite standby power sources (i.e., the DGs), and the implementation of a Configuration Risk Management Program.

In Condition B, the remaining OPERABLE DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

BASES

ACTIONS (continued)

C.1

In Condition C, with an opposite-unit DG inoperable, the remaining OPERABLE unit-specific DG and required qualified circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

D.1

With one or more buses with both of its required qualified circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the required qualified circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available required qualified circuits two less than required by the LCO, operation may continue for 24 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If two required qualified circuits are restored within 24 hours, unrestricted operation may continue. If only one required qualified circuit is restored within 24 hours, power operation continues in accordance with Condition A.

E.1 and E.2

In Condition E, with one DG inoperable and one or more buses with one qualified circuit inoperable or with one DG and one bus with both qualified circuits inoperable, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition D. This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time to restore the DG or the required qualified circuit(s) takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

ACTIONS (continued)

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no AC source to any division (one or more divisions de-energized), the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems-Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of one DG and one required qualified circuit on one or more buses, without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition E for a period that should not exceed 12 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

F.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

ACTIONS (continued)

G.1 and G.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies may be lost. At this severely degraded level, any further losses in the AC electrical power system may cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown. Examples of inoperabilities that require entry into Condition H are: 1) both DGs inoperable and both qualified circuits inoperable on one bus, and 2) one DG inoperable and both qualified circuits inoperable on one bus and one qualified circuit inoperable on the second bus.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 11), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4580 V is equal to the maximum operating voltage specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

Each SR 3.8.1.2 and SR 3.8.1.7 DG start requires the DG to achieve and maintain a steady state voltage and frequency range. The start signals used for this test may consist of one of the following signals:

a. Manual;

b. Simulated loss of ESF bus voltage by itself;

c. Simulated loss of ESF bus voltage in conjunction with an ESF actuation test signal; or

d. An ESF actuation test signal by itself.

For the purpose of SR 3.8.1.2 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer's recommended operating range (low lube oil and jacket water temperature alarm settings to the high lube oil and jacket water temperature alarm settings).

For the purposes of SR 3.8.1.7 testing, the DGs are started from normal standby conditions. Normal standby conditions for a DG mean that the diesel engine coolant and oil are being circulated (i.e., coolant is circulated based on temperature and oil is circulated continuously) and temperature is being maintained within the prescribed temperature bands of these subsystems when the diesel generator has been at rest for an extended period of time with the prelube oil and jacket water circulating systems operational. The prescribed temperature band is 110°F - 150°F which accounts for instrument tolerances. DG starts for these Surveillances are followed by a warmup period prior to loading.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to reduce stress and wear on diesel engines, a modified start is used in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of starts in accordance with SR 3.8.1.2.

SR 3.8.1.7 requires that the DG starts from normal standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see SR Note) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is also addressed in SR 3.8.1.2 Note.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures.

Although no power factor requirements are established by this SR, the DG is normally operated between 0 and 1000 kVARs. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients (e.g., changing bus loads) do not invalidate this test. Similarly, momentary kVAR transients outside of the specified range do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

This Surveillance demonstrates that each required (one of two transfer pumps per DG is "required" to support DG OPERABILITY) fuel oil transfer pump operates and transfers fuel oil from its associated storage tank(s) to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The single largest post-accident load associated with each DG is the Essential Service Water (SX) pump. The brake horsepower (BHP) and kW values for each SX pump at full load conditions from EC 622685 (Ref. 12) are as follows:

1A SX Pump	1297 BHP	1020 kW
1B SX Pump	1364 BHP	1075 kW
2A SX pump	1297 BHP	1020 kW
2B SX pump	1405 BHP	1105 kW

This Surveillance is accomplished by simultaneously tripping loads supplied by the DG which have a minimum combined load equivalent to the single largest post-accident load. This method is employed due to the difficulty of attaining SX full load conditions during normal plant operations.

As required by Regulatory Guide 1.9 (Ref. 3), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint (64.5 Hz), or 15% above synchronous speed (69 Hz), whichever is lower.

The voltage and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine/generator response under the simulated test conditions. This test simulates a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by three Notes. Note 1 states that momentary transients above the stated voltage limit immediately following a load rejection (i.e., the DG full load rejection) do not invalidate this test. The momentary transient is that which occurs immediately after the circuit breaker is opened, lasts a few milliseconds, and may or may not be observed on voltage recording or monitoring instrumentation. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.89. This power factor is representative of the actual inductive loading a DG would experience under design basis accident conditions. Under certain conditions; however, Note 3 allows the Surveillance to be conducted at a power factor other than ≤ 0.89. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.89 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.89 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power

SURVEILLANCE REQUIREMENTS (continued)

factor of 0.89 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained as close as practicable to 0.89 without exceeding the DG excitation limits.

SR 3.8.1.11

In general conformance with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time, and maintain a steady state voltage and frequency range.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or Residual Heat Removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, recommends demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load band equivalent to 105% to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are also applicable to this SR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

In order to ensure that the DG is tested under load conditions that bound design conditions and comply with the recommendations of Regulatory Guide 1.9 (Ref. 3) paragraph 2.2.9, testing must be performed using a power factor ≥ 0.8 and ≤ 0.89. This power factor range bounds the actual design basis inductive loading the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note which states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Alternatively, the DG can be operated until operating temperatures have stabilized. Note 2 states that momentary transients (e.g., due to changing bus loads) do not invalidate this test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a LOCA actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 10), paragraph 6.2.6(2).

The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.18

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by the automatic load sequence timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by a Note. The reason for the Note is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. R. M. Krich to NRC Document Control Desk Letter, "Request for Amendment to Technical Specifications, to Facility Operating Licenses, Emergency Diesel Generators, Completion Time Extension and Surveillance Requirement Change," January 20, 2000.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
9. 10 CFR 50, Appendix A, GDC 18.
10. IEEE Standard 308-1978.
11. Regulatory Guide 1.137, Rev. 1, October 1979.
12. EC 622685, Rev 0.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources-Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources-Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODES 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration;

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both;

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems; and

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite Diesel Generator (DG) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

One qualified circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems-Shutdown," ensures that all required loads are capable of being powered from offsite power. An OPERABLE DG, associated with one of the distribution subsystem division(s) required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required qualified circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Qualified circuits are those that are described in the UFSAR and are part of the licensing basis for the plant. A description of the qualified circuits is contained in the Bases for LCO 3.8.1, "AC Sources-Operating."

The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in normal standby with the engine hot and DG in standby at ambient conditions.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

It is acceptable for divisions to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required divisions.

BASES

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6, and at all times during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

BASES

ACTIONS (continued)

A.1

The qualified circuit would be considered inoperable if it were not available to one required ESF division. Since two divisions may be required by LCO 3.8.10, the one division with offsite power available may be capable of supporting sufficient required features (i.e., systems, subsystems, trains, components, and devices) to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

BASES

ACTIONS (continued)

<u>A.2.1, A.2.2, A.2.3, A.2.4, A.2.5, B.1, B.2, B.3, B.4, and B.5</u>

With the offsite circuit not available to one or more required divisions, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, operations involving positive reactivity additions, and declare the affected Low Temperature Overpressure Protection (LTOP) features required by LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System" inoperable. The Required Action to declare the affected LTOP features inoperable allows the operator to evaluate the current unit conditions and to determine which (if any) of the LTOP features have been affected by the loss of power. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained. Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

ACTIONS (continued)

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a division is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized division.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is not required to be met because the required OPERABLE DG is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is not required to be met because starting independence is not required with the DG that is not required to be operable.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude de-energizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

This page intentionally left blank.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil

BASES

BACKGROUND

Each Diesel Generator (DG) is provided with fuel oil capacity sufficient to operate that diesel for a period of 7 days while the DG is supplying the post loss of coolant accident load demand discussed in the UFSAR, Section 9.5.4.2 (Ref. 1). The station fuel oil system is comprised of two outside storage tanks (one 50,000 gal and one 125,000 gal) which are the source for all of the fuel oil needs for the station. These outside tanks are normally the source of "new" fuel oil. Each Unit 1 DG is provided with two 25,000 gallon inside storage tanks. Each Unit 2 DG is provided with one 50,000 gallon inside storage tank. These inside storage tanks are the source of the required "stored" fuel oil. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from the inside storage tank(s) to the day tank by either of two transfer pumps associated with each DG. Independence of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank(s) to result in the loss of more than one DG.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and particulate level.

BASES

APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 4), and in the UFSAR, Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems. Since the diesel fuel oil supports the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Stored diesel fuel oil is required to have sufficient supply for 7 days of post accident load operation. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an Anticipated Operational Occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources-Operating," and LCO 3.8.2, "AC Sources-Shutdown."
APPLICABILITY	The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since the stored diesel fuel oil supports LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil is required to be within limits when the associated DG is required to be OPERABLE.

BASES

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each DG Fuel Oil System. Complying with the Required Actions for one inoperable DG Fuel Oil System may allow for continued operation, and subsequent inoperable DG Fuel Oil System(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank(s). A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

BASES

ACTIONS (continued)

B.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.2. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

C.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.2 not within the required limits (after having been added to the storage tank(s); thus making it part of the stored fuel), a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

D.1

With a Required Action and associated Completion Time not met, or one or more DGs with fuel oil not within limits for reasons other than addressed by Conditions A through C, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at the post loss of coolant accident load demand discussed in the UFSAR, Section 9.5.4.2 (Ref. 1). The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

The tests of fuel oil prior to addition to the storage tank(s) are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between sampling (and associated results) of new fuel and addition of new fuel oil to the storage tank to exceed 30 days. The tests, limits, and applicable ASTM Standards for the tests listed in the Diesel Fuel Oil Testing Program of Specification 5.5.13 are as follows:

BASES

SURVEILLANCE REQUIREMENTS (continued)

a. Sample the new fuel oil in accordance with ASTM D4057-95 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-06b (Ref. 6) that the sample has an absolute specific gravity at 60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27° and ≤ 39° when tested in accordance with ASTM D1298-99 (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-93 (Ref. 6), or a water and sediment content within limits when tested in accordance with ASTM D2709-96e.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-06b (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-06b (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-95, ASTM D2622-98, ASTM D4294-98 ASTM D3120-06, or ASTM D5453-06 (Ref. 6). These additional analyses are required by Specification 5.5.13, "Diesel Fuel Oil Testing Program," to be performed within 30 days following sampling and addition. This 30 day time period is intended to assure: 1) that the sample taken is not more than 30 days old at the time of adding the fuel oil to the storage tank, and 2) that the results of a new fuel oil sample (sample obtained prior to addition but not more than 30 days prior to) are obtained within 30 days after addition. The 30 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D5452-98 (Ref. 6). This method involves a determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each tank must be considered and tested separately since the total stored fuel oil volume is contained in two or more interconnected tanks.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.3

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

BASES

REFERENCES

1. UFSAR, Section 9.5.4.2.
2. Regulatory Guide 1.137.
3. ANSI N195-1976, Appendix B.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. ASTM Standards: D4057-95; D975-06b; D1298-99; D4176-93; D2709-96e; D1552-95; D2622-98; D4294-98; D3120-06; D5453-06; D5452-98.
7. ASTM Standards, D975-06b, Table 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources-Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and AC instrument bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system for each unit consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Division 11 (21) and Division 12 (22)). Each subsystem consists of one 125 VDC battery, the associated battery charger for each battery, and all the associated control equipment and interconnecting cabling.

During normal operation, the 125 VDC loads are powered from the battery chargers with the batteries floating on the system. In case of a loss of normal power to the battery charger, the DC load is automatically powered from the station battery.

The Division 11 (21) and Division 12 (22) DC electrical power subsystems provide the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. The DC electrical power subsystems also provide DC electrical power to the inverters, which in turn power the AC instrument buses. Additionally, the Class 1E 125 VDC electrical power subsystems provide power to the 6.9 kV Reactor Coolant Pump (RCP) breakers and the non-Class 1E 125 VDC buses. The connection between the Class 1E and non-Class 1E 125 VDC buses contains fuses to ensure that a fault on the non-Class 1E bus does not cause a loss of the Class 1E bus.

BASES

BACKGROUND (continued)

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System-Operating," and LCO 3.8.10, "Distribution Systems-Shutdown."

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels. While it is possible to interconnect the Unit 1 and Unit 2 DC electrical power subsystems, they normally remain disconnected, except when a DC source must be taken out of service for the purposes of maintenance and/or testing, or in the event of a failure of a DC source.

The crosstie between 125 VDC ESF buses 111 and 211 and the crosstie between 125 VDC ESF buses 112 and 212 are each provided with two normally locked open, manually operated circuit breakers. No interlocks are provided since the interconnected buses are not redundant. However, if one battery is inoperable, procedural and administrative controls are used to limit the connected load to 200 amps based on not exceeding the OPERABLE battery capacity. These controls ensure that combinations of maintenance and test operations will not preclude the system capabilities to supply power to the ESF DC loads. The provisions of administratively controlled, manually actuated, interconnections between the non-redundant Class 1E DC buses increases the overall reliability and availability of the DC systems for each unit in that it provides a means for manually providing power to a DC bus at a time when it would otherwise have to be out-of-service (e.g., to perform a battery discharge test during an outage, to replace a damaged cell, etc.). Crosstie breaker closed alarms are also provided to alert the operator when the units are crosstied.

BASES

BACKGROUND (continued)

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in UFSAR. Chapter 8 (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The Division 11 (21) and Division 12 (22) DC electrical power subsystem batteries are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limit is as denoted below:

Battery Bank 111 (1DC01E): 107.3 VDC
Battery Bank 112 (1DC02E): 107.7 VDC
Battery Bank 211 (2DC01E): 107.3 VDC
Battery Bank 212 (2DC02E): 106.5 VDC

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 volts for a 58 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.22 Vpc corresponds to a total float voltage output of 128.8 volts for a 58 cell battery as discussed in UFSAR, Chapter 8 (Ref. 4).

Each Division 11 (21) and Division 12 (22) DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads discussed in the UFSAR, Chapter 8 (Ref. 4).

BASES

BACKGROUND (continued)

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger if the discharge was significant, e.g., following a battery service test, until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 5), and in the UFSAR, Chapter 15 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the DC electrical power distribution subsystem OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power sources; and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The DC electrical power subsystems, each subsystem consisting of:

a. a battery;

b. battery charger; and

c. the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the division,

are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an Anticipated Operational Occurrence (AOO) or a postulated DBA. Loss of any division DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). Furthermore, at least one crosstie breaker between Division 11 and Division 21, and at least one crosstie breaker between Division 12 and Division 22, is required to be open to maintain independence between the units.

An OPERABLE DC electrical power subsystem requires the required battery and respective charger to be operating and connected to the associated DC bus.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 5 and 6 are addressed in LCO 3.8.5, "DC Sources-Shutdown."

BASES

ACTIONS

A.1, A.2, A.3 and A.4

Condition A addresses the event of having one battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period.

Required Action A.1 provides for restoration of electrical power to the associated DC bus by use of the crosstie capability to the opposite unit. The 2 hour Completion Time allows adequate time to evaluate the cause for battery charger failure, to determine whether the opposite unit's DC bus is available for support, and to perform the crosstie procedure. The battery charger is required to be restored to OPERABLE status within 7 days in order to reestablish the independence of DC subsystems, while providing a reasonable amount of time for repairs. By limiting the crosstied conditions of operating units to 7 days, the likelihood of an event occurring which could place either unit in jeopardy is minimized. (Note, there are no load restrictions applicable to the opposite unit's DC bus in this condition.)

BASES

ACTIONS (continued)

Required Action A.2 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.3) from any discharge that might have occurred due to the charger inoperability. A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.3).

BASES

ACTIONS (continued)

Required Action A.3 requires that the battery float current be verified as less than or equal to 3 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 3 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.4 limits the restoration time for the inoperable battery charger to 7 days. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to operable status.

B.1

Condition B addresses the situation of crosstieing the operating unit's DC bus to the opposite unit, which has an inoperable battery charger, when the opposite unit is operating in MODE 1, 2, 3, or 4. This provision is included to accommodate unexpected failures, maintenance, and/or testing of the opposite unit's DC subsystems. The Completion Time for Required Action B.1 of 204 hours is adequate to allow testing and restoration activities. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. In this Condition, the opposite unit's battery is assumed to remain OPERABLE. Therefore, the function of the crosstie is to maintain the opposite unit's battery fully charged and to supply the minimal opposite unit DC loads. The 204 hours is based on the 7 days the opposite unit has to restore the inoperable charger and the 36 hours the opposite unit would have to reach MODE 5, if the charger is not restored to OPERABLE status. When the opposite unit reaches MODE 5, Condition C is entered. Requiring the associated crosstie breaker to be opened within 204 hours also ensures that independence of the DC subsystems is reestablished.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C addresses an operating unit's DC bus that is crosstied to the opposite unit's associated DC bus, which has an inoperable source (i.e., battery or battery charger), when the opposite unit is shutdown. This provision is included to accommodate maintenance and/or testing of the shutdown unit's DC subsystems.

With the shutdown unit's battery inoperable, the operating unit will be required to supply all loads on the shutdown unit's crosstied bus should an event occur on the shutdown unit. Therefore, Required Action C.1 specifies that the possible loading on the shutdown unit's DC bus be verified to be ≤ 200 amps once per 12 hours. Limiting the load to 200 amps, ensures that the operating unit's DC subsystem will not be overloaded in the event of a concurrent event on the operating unit. Required Action C.1 is modified by a Note only requiring Required Action C.1 when the opposite unit has an inoperable battery.

Required Action C.2 requires the associated crosstie breaker to be opened within 7 days or in accordance with the Risk Informed Completion Time Program and ensures that measures are being taken to restore the inoperable battery or battery charger and reestablish independence of the DC subsystems.

D.1

Condition D represents one division with a loss of ability to completely respond to an event, and a potential loss of ability for the DC division to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system division. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

BASES

ACTIONS (continued)

If one of the required DC electrical power subsystems is inoperable for reasons other than Condition A, B, or C (e.g., inoperable battery or one DC division crosstied to the opposite-unit DC division that does not have an inoperable battery charger), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the minimum necessary DC electrical power subsystems to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

<u>E.1 and E.2</u>

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status, or the crosstie breaker(s) cannot be opened, within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the connected loads and the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state, while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.20 Vpc or 127.6 volts at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 8), the battery charger output capacity is recommended to be based on the largest combined demands of the various steady state loads and the charging demands to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 400 amps at the minimum established float voltage for 8 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 3 amps. This option is required to be performed during MODES 5 and 6 since it would require the DC electrical power subsystem to be inoperable during performance of the test.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.3

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1978.
4. UFSAR, Chapter 8.
5. UFSAR, Chapter 6.
6. UFSAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974
8. Regulatory Guide 1.32, February 1977.

BASES

This page intentionally left blank.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources-Shutdown

BASES

BACKGROUND	A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources-Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystem is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specifications requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The DC electrical power subsystem, the required subsystem consisting of its associated battery and battery charger and at least one of the associated crosstie breakers open to maintain independence between the units, and the corresponding control equipment, and interconnecting cabling within the division are required to be OPERABLE to support the required division of the distribution system. This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

LCO 3.8.5 is modified by a Note which allows the required DC electrical power subsystem to be crosstied to the opposite unit, when the opposite unit is in MODE 1, 2, 3, or 4 with an inoperable charger. No load restrictions are placed on the bus loading, when the required DC electrical power subsystem is crosstied.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and at all times during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

BASES

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features' LCO ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, operations involving positive reactivity additions, and declare the affected Low Temperature Overpressure Protection (LTOP) features, required by LCO 3.4.12, inoperable). The Required Action to declare the associated LTOP features inoperable allows the operator to evaluate the current unit conditions and to determine which (if any) of the LTOP features have been affected by the inoperable DC electrical power subsystem. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystem and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystem should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

ACTIONS (continued)

B.1 and B.2

Condition B addresses a shutdown unit's DC bus that is crosstied to the opposite unit's associated DC bus, which has an inoperable source, when the opposite unit is also shutdown. This provision is included to accommodate maintenance and/or testing of the opposite unit's DC subsystems.

With the opposite unit's battery inoperable, the unit-specific DC subsystem will be required to supply all loads on the opposite unit's crosstied bus should an event occur on the opposite unit. Therefore, Required Action B.1 specifies that the possible loading on the opposite unit's DC bus be verified to be ≤ 200 amps once per 12 hours. Limiting the load to 200 amps, ensures that the unit-specific DC subsystem will not be overloaded in the event of a concurrent event on the unit. Required Action B.1 is modified by a Note requiring Required Action B.1 when the opposite unit has an inoperable battery.

Required Action B.2 requires the associated crosstie breaker to be opened within 7 days ensures that measures are being taken to reestablish independence of the DC subsystems.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires application of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

BASES

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND	This LCO delineates the limits on battery float current as well as electrolyte temperature, level, and float voltage for the DC power subsystem source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources-Operating," and LCO 3.8.5, "DC Sources-Shutdown." In addition to the limitations of this Specification, Specification 5.5.17, “Battery Monitoring and Maintenance Program,” for monitoring various battery parameters is based on the recommendations of IEEE Standard 450, “IEEE Recommended Practice For Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications” (Ref.1). The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 120 volts for a 58 cell battery (i.e., cell voltage of 2.065 volts per cell (Vpc)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.065 Vpc, the battery cell will maintain its capacity for 30 days without further charging per manufacturer’s instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.22 Vpc corresponds to a total float voltage output of 128.8 volts for a 58 cell battery as discussed in UFSAR, Chapter 8 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 3) and Chapter 15 (Ref. 4), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining at least one division of DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Battery parameters satisfy the Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.17.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery parameter limits are only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

BASES

ACTIONS

The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each affected battery. Complying with the Required Actions for one battery may allow for continued operation, and subsequent battery parameters out of limits are governed by separate Condition entry and application of associated Required Actions.

A.1, A.2, and A.3

With one of more cells in one battery < 2.07 volts, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one battery < 2.07 volts, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify “perform,” a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered.

If SR 3.8.6.1 is failed when in Condition A, then there is not assurance that there is still sufficient battery capacity to perform the intended function and Condition F must be entered and the battery declared inoperable immediately.

BASES

ACTIONS (continued)

B.1 and B.2

One battery with float current > 3 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. Condition A addressed charger inoperability. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

If the float voltage is found to be satisfactory but there are one or more battery cells with float voltage less than 2.07 volts, the associated "OR" statement in Condition F is applicable and the battery must be declared inoperable immediately. If float voltage is satisfactory and there are no cells less than 2.07 volts there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger. A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

BASES

ACTIONS (continued)

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 volts and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies “perform,” a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

<u>C.1, C.2, and C.3</u>

With one battery with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.17). They are modified by a note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.17 item b to initiate action to equalize and test in accordance with manufacturer’s recommendation are taken from Annex D of IEEE Standard 450 (Ref. 1). They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer’s recommended testing the battery may have to be declared inoperable and the affected cell(s) replaced.

BASES

ACTIONS (continued)

D.1

With one battery with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With two batteries with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, and E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC battery must be declared inoperable. Additionally, discovering one battery with one or more battery cells float voltage less than 2.07 volts and float current greater than 3 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 Action A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 3 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 127.6 volts at the battery terminals, or 2.20 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltage in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.17. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 volts. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60ºF). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6, however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test and the test discharge rate must envelop the duty cycle of the service test if the modified performance discharge test is performed in lieu of a service test.

BASES

SURVEILLANCE REQUIREMENTS (continued

It may consist of just two rates: for instance the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelop the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is > 10% below the manufacturer's rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

BASES

REFERENCES

1. IEEE-450-1995.
2. UFSAR, Chapter 8.
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 15.
5. IEEE-485-1983, June 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters-Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC instrument buses because of the stability and reliability they provide. Each of the four AC instrument buses (2 per division) is normally supplied AC electrical power by a dedicated inverter. The inverters can be powered from an AC source/rectifier or from an associated 125 VDC battery. The battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). Specific details on inverters and their operating characteristics are found in the UFSAR, Chapter 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume Engineered Safety Feature Systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the plant. This includes maintaining required AC instrument buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power sources; and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an Anticipated Operational Occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the AC instrument buses even if the 4.16 kV safety buses are de-energized.

OPERABLE inverters require the associated instrument bus to be powered by the inverter with output voltage within tolerances, and power input to the inverter from the associated 125 VDC battery. The power supply may be from an AC source via rectifier as long as the battery is connected as the uninterruptible power supply.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in LCO 3.8.8, "Inverters-Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC instrument bus may be inoperable unless it is automatically or manually re-energized, as appropriate, from its Class 1E constant voltage source transformer.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems-Operating" for any de-energized instrument bus. This ensures that the instrument bus is re-energized within 2 hours.

BASES

ACTIONS (continued)

Required Action A.1 allows 7 days to fix the inoperable inverter and return it to service. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The 7 day limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC instrument buses is the preferred source for powering instrumentation trip setpoint devices.

With a required inverter inoperable, the following compensatory actions will be taken (Ref. 4):

a. Entry into the extended inverter Completion Time (CT) will not be planned concurrent with Diesel Generator (DG) maintenance on the associated train.

b. Entry into the extended inverter CT will not be planned concurrent with planned maintenance on another RPS or ESFAS channel that could result in that channel being in a tripped condition.

These actions are taken because it is recognized that with an inverter inoperable and the instrument bus being powered by the constant voltage transformer, instrument power for that train is dependent on power from the associated DG following a loss of offsite power event.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC instrument buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC instrument buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 8.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. Safety Evaluation, dated November 19, 2003, associated with Byron Technical Specification Amendment No. 135 and Braidwood Technical Specification Amendment No. 129.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters-Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters-Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the inverter to each required AC instrument bus during MODES 5 and 6 ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specifications requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO (continued)

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. One AC instrument bus division energized by two battery powered inverters provides uninterruptible supply of AC electrical power to at least one AC instrument bus division even if the 4.16 kV safety buses are de-energized. OPERABILITY of these two inverters requires that the associated AC instrument buses be powered by the inverters. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6, and at all times during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

BASES

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, operations involving positive reactivity additions, and declare the associated Low Temperature Overpressure Protection (LTOP) features inoperable). The Required Action to declare the associated LTOP features inoperable allows the operator to evaluate the current unit conditions and to determine which (if any) of the LTOP features have been affected by the inoperable inverter(s). If the LTOP features have not been affected, then unnecessarily restrictive actions may be averted. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and required AC instrument buses energized. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the AC instrument buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

This page intentionally left blank.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems-Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC instrument bus electrical power distribution systems are divisionalized into two redundant and independent AC, DC, and AC instrument bus electrical power distribution subsystems.

The AC electrical power subsystem for each division consists of a primary 4.16 kV Engineered Safety Feature (ESF) bus and two primary 480 V ESF buses. The division also includes (but is not included in the subsystem required to be OPERABLE by LCO 3.8.9) secondary 480 and 120 V buses, motor control centers, and distribution panels. Each 4.16 kV ESF bus has at least one separate and independent offsite source of power as well as a dedicated onsite Diesel Generator (DG) source. Each 4.16 kV ESF bus is normally connected to a normal offsite source. After a loss of the normal offsite power source to a 4.16 kV ESF bus the onsite emergency DG supplies power to the 4.16 kV ESF bus. A transfer to the reserve offsite source can be accomplished manually. Control power for the 4.16 kV breakers is supplied from the Class 1E 125 VDC electrical power distribution subsystem. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources-Operating," and the Bases for LCO 3.8.4, "DC Sources-Operating."

The four 120 VAC instrument buses (considered distinct from the AC electrical power distribution subsystem) are arranged in two load groups per division and are normally powered from the inverters. The alternate power supply for the instrument buses are Class 1E constant voltage source transformers powered from the same division as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters-Operating." Each constant voltage source transformer is powered from a Class 1E AC bus.

There are two independent 125 VDC electrical power distribution subsystems (one for each division).

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1), and in the UFSAR, Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC instrument bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC instrument bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power sources; and

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems ensure the availability of AC, DC, and AC instrument bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an Anticipated Operational Occurrence (AOO) or a postulated DBA. The AC, DC, and AC instrument bus electrical power distribution subsystems are required to be OPERABLE.

BASES

LCO (continued)

Maintaining the Division 1 and Division 2 AC, DC, and AC instrument bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages. The division also includes (but is not included in the subsystem required to be OPERABLE by LCO 3.8.9) secondary 480 and 120 V buses, motor control centers, and distribution panels. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE instrument bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage, inverter using AC source, or Class 1E constant voltage transformer.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in LCO 3.8.10, "Distribution Systems-Shutdown."

BASES

ACTIONS

A.1

With one AC bus, except AC instrument buses, inoperable, the remaining AC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC bus must be restored to OPERABLE status within 8 hours or in accordance with the Risk Informed Completion Time Program.

Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit, and on restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected division, to the actions associated with taking the unit to shutdown within this time limit; and

b. The low probability for an event in conjunction with a single failure of a redundant component in the division with AC power.

BASES

ACTIONS (continued)

B.1

With one AC instrument bus inoperable, the remaining OPERABLE AC instrument buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC instrument bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, inverter using AC source, or Class 1E constant voltage transformer. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

BASES

ACTIONS (continued)

Condition B represents one AC instrument bus without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining instrument buses and restoring power to the affected instrument bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate AC instrument power. Taking exception to LCO 3.0.2 for components without adequate AC instrument power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate AC instrument power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected bus(es); and

c. The low probability for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the AC instrument bus(es) to OPERABLE status, the redundant capability afforded by the other OPERABLE instrument buses, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

C.1

With one DC bus inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the DC bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

BASES

ACTIONS (continued)

Condition C represents one division without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning and not crosstied to the other unit. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining divisions and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

c. The low probability for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 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 plant systems.

E.1

With two electrical power distribution subsystems inoperable that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC instrument bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems-Shutdown

BASES

BACKGROUND	A description of the AC, DC, and AC instrument bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems-Operating."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC instrument bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. The OPERABILITY of the AC, DC, and AC instrument bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY. The OPERABILITY of the minimum AC, DC, and AC instrument bus electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that: a. The unit can be maintained in the shutdown or refueling condition for extended periods; b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident. The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Various subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific unit condition. Implicit in those requirements is the OPERABILITY of necessary support features (i.e. systems, subsystems, trains, components, and devices). This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required subsystems, equipment, and components - whether specifically addressed in an LCO or implicitly required via the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and at all times during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

The AC, DC, and AC instrument bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

BASES

ACTIONS

LCO 3.0.3 is not applicable while in MODE 5 or 6. However, since irradiated fuel assembly movement can occur in MODE 1, 2, 3, or 4, the ACTIONS have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be sufficient reason to require a reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, A.2.4, A.2.5, and A.2.6

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable (Required Action A.1), appropriate restrictions are implemented in accordance with the affected required feature LCO's Required Actions. In many instances, however, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions of Required Actions A.2.1 through A.2.4 is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

BASES

ACTIONS (continued)

Notwithstanding performance of the above conservative Required Actions, a required Residual Heat Removal (RHR) train and/or a required Low Temperature Overpressure Protection (LTOP) feature, may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR or LTOP ACTIONS would not be entered. Therefore, Required Actions A.2.5 and A.2.6 are provided to direct declaring RHR and LTOP features inoperable and declaring the associated RHR train "not in operation" (note, this does not require the RHR train to be shut down if operating, only that the associated RHR train not be credited as the required operating train), which results in taking the appropriate actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and AC instrument bus electrical power distribution subsystems are functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentration ensures the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity that are hydraulically coupled to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. The specified boron concentration is controlled by plant procedures to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity).

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration (Ref. 2).

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized, the vessel head is unbolted, and removed. The refueling cavity is then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps.

BASES

BACKGROUND (continued)

The pumping action of the RHR System in the RCS, and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity, ensure adequate mixing of the borated water. The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentration in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis (Ref. 3) and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, all filled portions of the RCS, the water volume in the spent fuel pool, the transfer tube, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 3). A detailed discussion of this event is provided in Bases B 3.1.1, "SHUTDOWN MARGIN (SDM)."

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO requires that a minimum boron concentration be maintained in all filled portions of the RCS, the refueling canal, and the refueling cavity, that are hydraulically coupled to the reactor core, while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. In MODES 1 and 2 with $k_{eff} \geq 1.0$, LCO 3.1.4, "Rod Group Alignment Limits," LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits," ensure an adequate amount of negative reactivity is available to shutdown the reactor. In MODE 2 with $k_{eff} < 1.0$ and MODES 3, 4, and 5, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

ACTIONS

A.1, A.2, and A.3

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO.

BASES

ACTIONS (continued)

If the boron concentration of any coolant volume in the filled portions of the RCS, the refueling canal, or the refueling cavity is less than its limit, an inadvertent criticality may occur due to an incorrect fuel loading. To minimize the potential of an inadvertent criticality resulting from a fuel loading error, all operations involving CORE ALTERATIONS and positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position, or heating or cooling the coolant volume for the purpose of system temperature control within established procedures.

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, action to restore the boron concentration must be initiated immediately.

There are no safety analysis assumptions of boration flow rate and concentration that must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in all filled portions of the RCS, the refueling canal, and the refueling cavity, that are hydraulically coupled with the reactor core, is within the COLR limits. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. UFSAR, Section 9.3.4.
3. UFSAR, Section 15.4.6.

This page intentionally left blank.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Isolation Valves

BASES

BACKGROUND

During MODE 6 operations, all isolation valves for reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves (CV111B, CV8428, CV8441, CV8435, and CV8439 or alternate valves that isolate the unborated water sources) must be secured in the closed position.

The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by reducing the boron concentration is inappropriate during MODE 6, isolation of all unborated water sources prevents an unplanned boron dilution.

The Refueling Water Storage Tank (RWST) is assumed to be a boration source. With the RWST boron concentration less than the refueling boron concentration specified in the COLR, the RWST becomes a potential dilution source and all suction source isolation valves are considered unborated water source isolation valves. These valves (CV112D, CV112E, SI8806, SI8812A, SI8812B, and SI8927) must be secured in the closed position.

The Boric Acid Storage Tank (BAST) is also assumed to be a boration source. With the BAST boron concentration less than the refueling boron concentration specified in the COLR, the BAST becomes a potential dilution source and the emergency boration valve is considered an unborated water source isolation valve. This valve (CV8104) must be secured in the closed position.

BASES

APPLICABLE SAFETY ANALYSES	The possibility of an uncontrolled boron dilution event (Ref. 1) occurring during MODE 6 refueling operations is precluded by adherence to this LCO, which requires that potential dilution sources be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portion of the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required for MODE 6. The RCS unborated water source isolation valves satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that flow paths to the RCS from unborated water sources be isolated to prevent unplanned boron dilution during MODE 6 and thus avoid a reduction in SDM.
APPLICABILITY	In MODE 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of all sources of unborated water to the RCS. For all other MODES, the boron dilution accident was analyzed and was found to be capable of being mitigated.

BASES

ACTIONS

The ACTIONS table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1, A.2, and A.3

Continuation of CORE ALTERATIONS is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS must be suspended immediately. The Completion Time of "immediately" for performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valves secured closed. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of "immediately" requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position without delay. Once actions are initiated, they must be continued until the valves are secured in the closed position.

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

Condition A has been modified by a Note to require that Required Action A.3 be completed whenever Condition A is entered.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution paths. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that all unborated water sources are isolated, precluding a dilution. The boron concentration is checked during MODE 6 under SR 3.9.1.1. This SR demonstrates that valves CV111B, CV8428, CV8441, CV8435, and CV8439 are secured closed by the use of mechanical stops, removal of air, or removal of electrical power. Alternate valves may be secured closed in lieu of these unborated water source isolation valves provided it is ensured that the potential dilution water sources are isolated.

In the unlikely event that the RWST or the BAST becomes a dilution source (i.e., its boron concentration less than the refueling boron concentration specified in the COLR) all required isolation valves must be secured in the closed position to isolate all possible dilution paths. With the RWST considered a potential dilution source, all suction source isolation valves (CV112D, CV112E, SI8806, SI8812A, SI8812B, and SI8927) must be secured in the closed position. With the BAST considered a potential dilution source, the emergency boration valve (CV8104) must be secured in the closed position. Verification of the secured valve position through a system walkdown ensures the isolation of possible dilution paths.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.4.6.

2. NUREG-0800, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The Gamma-Metrics source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The use of portable detectors is permitted, provided the LCO requirements are met.

The source range neutron flux monitors, each having a source range channel and a source range post accident channel, are enriched U-235 fission chambers operating in the ion chamber region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The source range instrument range covers six decades (1 to 1E+6 cps) (Ref. 1). The source range post accident instrument range also covers six decades (0.1 to 1E+5 cps). The detectors also provide continuous visual indication in the control room to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in Reference 2. If used, portable detectors must be functionally equivalent to the installed NIS source range monitors.

BASES

APPLICABLE SAFETY ANALYSES	Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 3) or an improperly loaded fuel assembly. The need for a safety analysis for an uncontrolled boron dilution accident is eliminated by isolating all unborated water sources as required by LCO 3.9.2, "Unborated Water Source Isolation Valves. The source range neutron flux monitors have no safety function in MODE 6 and are not assumed to function during any UFSAR design basis accident or transient. The source range neutron flux monitors provide the only on-scale monitoring of the neutron flux level during refueling. Therefore, they are being retained in the Technical Specifications.
LCO	This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. While multiple source range channels are available (i.e., two source range channels and two source range post accident channels), one channel from each source range neutron flux monitor is required to be OPERABLE. In addition, each monitor must provide visual indication.
APPLICABILITY	In MODE 6, two source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODE 2 below the intermediate range neutron flux interlock setpoint (P-6), and in MODES 3, 4, and 5 with the Rod Control System capable of rod withdrawal or with all rods not fully inserted, the source range neutron flux monitors are required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

BASES

ACTIONS

A.1 and A.2

With only one required source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 or A.2 shall not preclude completion of movement of a component to a safe position or normal heatup/cooldown of the coolant volume for the purpose of system temperature control.

B.1 and B.2

With no required source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. Therefore, action to restore a monitor to OPERABLE status shall be initiated immediately and continued until a source range neutron flux monitor is restored to OPERABLE status.

Since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Table 7.5-2.

2. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.

3. UFSAR, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During movement of RECENTLY IRRADIATED FUEL assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODES 5 and 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are filtered, closed, or capable of being closed. Since there is no significant potential for containment pressurization, the 10 CFR 50, Appendix J, leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 50.67 (Ref 5). In addition, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

BASES

BACKGROUND (continued)

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of RECENTLY IRRADIATED FUEL assemblies within containment with the equipment hatch installed, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts be approximately equally spaced. During movement of RECENTLY IRRADIATED FUEL assemblies within containment and the equipment hatch not intact, the OPERABILITY requirements of the Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System must be met. The OPERABILITY requirements of the FHB Ventilation System are provided in TS 3.7.13, "Fuel Handling Building Exhaust Filter Plenum (FHB) Ventilation System."

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 in accordance with LCO 3.6.2, "Containment Air Locks." The two air locks are the personnel air lock and the emergency air lock. Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During movement of RECENTLY IRRADIATED FUEL assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed. An exception, however, is provided for the personnel air lock. It is acceptable to have both doors of the personnel air lock opened simultaneously provided the FHB Ventilation System is in compliance with TS 3.7.13.

The closure restrictions are sufficient to restrict unfiltered fission product radioactivity releases from containment to the environment due to a fuel handling accident involving RECENTLY IRRADIATED FUEL during refueling.

BASES

BACKGROUND (continued)

The Containment Ventilation Isolation System consists of the normal purge subsystem, the mini purge subsystem, and the post Loss Of Coolant Accident purge subsystem. These three subsystems contain penetrations which provide direct access from the containment to the outside atmosphere. In MODE 6, the minipurge subsystem is normally used to exchange large volumes of containment air to support refueling operations. Each penetration contains inside and outside containment isolation valves which close automatically on an actuation signal; however, during movement of RECENTLY IRRADIATED FUEL within containment, each penetration providing direct access from the containment atmosphere to the outside atmosphere will be closed by a manual or automatic isolation valve, blind flange, or equivalent in accordance with LCO 3.9.4.c. The Containment Ventilation Isolation System is not relied on to provide automatic containment closure and; therefore, need not be OPERABLE. A list of the instrumentation which functions to isolate the valves in these penetrations is provided in LCO 3.3.6, "Containment Ventilation Isolation Instrumentation."

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by a closed automatic isolation valve, a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods allowed under the provisions of 10 CFR 50.59 may include use of a material that can provide a temporary atmospheric pressure ventilation barrier during movement of RECENTLY IRRADIATED FUEL within the containment.

BASES

APPLICABLE SAFETY ANALYSES	During movement of RECENTLY IRRADIATED FUEL assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 1). Fuel handling accidents, analyzed in Reference 2, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.7, "Refueling Cavity Water Level," ensure that the release of fission product radioactivity, subsequent to a fuel handling accident in containment, results in doses that are within the 10 CFR 50.67 (Ref. 5) limits. The radiological dose assessments for the Design Basis Fuel Handling Accident in containment were performed in accordance with the guidance of Regulatory Guide 1.183 (Ref 4). When moving RECENTLY IRRADIATED FUEL in containment, the requirements of the LCO must be met with the exception that LCO 3.9.4.a need not be met if at least one train of the FHB Ventilation System is OPERABLE as specified in the Note. This exception permits movement of RECENTLY IRRADIATED FUEL with both personnel air lock doors open or the equipment hatch not intact. When moving fuel in the containment that is not RECENTLY IRRADIATED FUEL, the LCO is not applicable. Due to radioactive decay, neither containment closure nor an OPERABLE FHB Ventilation System train are required to meet the dose limits of 10 CFR 50.67 during a fuel handling accident. Another consideration, which may result in a limiting decay time prior to fuel handling, is the impact of decay heat on the spent fuel pool cooling requirements described in Reference 3. Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO limits the consequences of a fuel handling accident involving handling RECENTLY IRRADIATED FUEL in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed.

BASES

LCO (continued)

The requirements for this LCO ensure that containment closure is achieved and, therefore, meet the assumptions used in the safety analysis to ensure that radiological doses are within the acceptance limits.

The LCO is modified by a Note which allows both personnel air lock doors to be open or the equipment hatch not intact when the FHB Ventilation System is in compliance with TS 3.7.13. When the equipment hatch is installed it serves to contain fission product radioactivity that may be released following a fuel handling accident in the containment. When the equipment hatch is not intact, or when both doors of the personnel air lock are simultaneously opened, the internal containment pressure is essentially equal to the internal pressure of the fuel handling building. In the event of a fuel handling accident in the containment, realigning of the fuel handling building ventilation system creates a negative pressure in the containment and fuel handling building relative to the auxiliary building and outside atmosphere. The negative pressure ensures that any radioactivity released to the containment atmosphere will either remain in the containment or be filtered through a FHB Ventilation System train. As such, with the equipment hatch not intact, or with both personnel air lock doors open, the consequences of a fuel handling accident involving RECENTLY IRRADIATED FUEL in containment would not exceed those calculated for a fuel handling accident involving RECENTLY IRRADIATED FUEL in the fuel handling building.

In addition, a commitment has been made to implement compensatory measures during movement of irradiated fuel as described in UFSAR Section 15.7.4, “Fuel Handling Accidents.” These compensatory measures support the Alternate Source Term methodology and reduce doses even further below that provided by natural decay and avoid unmonitored releases in the event of a postulated fuel handling accident.

BASES

APPLICABILITY	The containment penetration requirements are applicable during movement of RECENTLY IRRADIATED FUEL assemblies within containment because this is when there is a potential for a limiting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODE 5, and in MODE 6 when movement of RECENTLY IRRADIATED FUEL assemblies within containment are not being conducted, the potential for a limiting fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.
ACTIONS	A.1 If the containment equipment hatch, air lock doors, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, the unit must be placed in a condition where containment closure is not needed. This is accomplished by immediately suspending movement of RECENTLY IRRADIATED FUEL assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.4.1 This Surveillance demonstrates that each of the containment penetrations required to be isolated is isolated. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 15.7.4. 2. NUREG-0800, Section 15.0.1, Rev. 0, July 2000. 3. NUREG-0800, Section 9.1.3. 4. Regulatory Guide 1.183, July 2000. 5. 10 CFR 50.67.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation-High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSIS

While there is no explicit analysis assumption for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. In addition, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not reduced. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

RHR and Coolant Circulation-High Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange because the volume of water above the reactor vessel flange provides backup decay heat removal capability. One RHR loop is required to be in operation and OPERABLE to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Management of gas voids is important to RHR System OPERABILITY.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

BASES

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.7, "Refueling Cavity Water Level." Requirements for the RHR System in MODES 1, 2, 3, 4, and 5 are covered by LCO 3.4.6, "RCS Loops-MODE 4," LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled," LCO 3.5.2, "ECCS-Operating," and LCO 3.5.3, "ECCS-Shutdown." RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

A.1, A.2, A.3, and A.4

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur by the addition of water with a lower boron concentration than that contained in the RCS. Therefore, actions that could result in a reduction in the coolant boron concentration must be suspended immediately.

With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition. Therefore, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. Suspension of these activities shall not preclude completion of movement of a component to a safe condition.

With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, removal of decay heat is by ambient losses only. Therefore, corrective actions shall be initiated immediately and shall continue until the RHR loop requirements are met.

BASES

ACTIONS (continued)

With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Therefore, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to provide mixing of the borated coolant to prevent thermal and boron stratification in the core. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.2

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR 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 is 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 configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 criteria 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 RHR 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.

RHR 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. UFSAR, Section 5.4.7.

This page intentionally left blank.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.
APPLICABLE SAFETY ANALYSIS	While there is no explicit analysis assumption for the decay heat removal function of the RHR System in MODE 6, if the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. In addition, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge. RHR and Coolant Circulation-Low Water Level satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Both RHR loops must be OPERABLE in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange. In addition, one RHR loop must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. However, the LCO is modified by a Note that permits the required RHR loop to be removed from operation and considered OPERABLE when aligned to, or during transitioning to or from, the Refueling Water Storage Tank (RWST) to support filling or draining the refueling cavity, or to support required testing, if capable of being realigned to the RCS. Management of gas voids is important to RHR System OPERABILITY.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal and mixing of the borated coolant. Requirements for the RHR System in MODES 1, 2, 3, 4, and 5 are covered by LCO 3.4.6, "RCS Loops-MODE 4," LCO 3.4.7, "RCS Loops-MODE 5, Loops Filled," LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled," LCO 3.5.2, "ECCS-Operating," and LCO 3.5.3, "ECCS-Shutdown." RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level."

BASES

ACTIONS

A.1 and A.2

With one or more RHR loops inoperable, the RHR System may not be capable of removing decay heat and mixing the borated coolant. Therefore, action shall be immediately initiated and continued until the required number of RHR loops are restored to OPERABLE status or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1, B.2, and B.3

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations can occur by the addition of water with a lower boron concentration than that contained in the RCS. Therefore, actions that would result in a reduction in the coolant boron concentration must be suspended immediately.

In addition, with no forced circulation, any decay heat removal occurs by ambient losses only. Therefore, action shall be initiated immediately to restore one RHR loop to operation. Once initiated, actions shall continue until one RHR loop has been restored to operation.

BASES

ACTIONS (continued)

With no RHR loop in operation, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Therefore, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to provide mixing of the borated coolant to prevent thermal and boron stratification in the core. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.6.2

Verification that the required pump is OPERABLE ensures a RHR pump can be placed in operation, if needed, to maintain decay heat removal and borated coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the pump. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.6.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR 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 is supplemented by system

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 configuration, such as stand-by versus operating conditions.

The RHR 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 criteria 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 RHR 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.

RHR 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

BASES

REFERENCES 1. UFSAR, Section 5.4.7.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. This requirement ensures a sufficient level of water is maintained in the refueling cavity to retain iodine fission product activity resulting from a fuel handling accident in containment (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to within 10 CFR 50.67 limits (Ref. 3).
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the water level in the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.183 (Ref. 1). The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and doses are maintained within allowable limits (Refs. 2 and 3). The minimum decay time prior to allowing fuel handling is addressed in the fuel handling accident dose analysis. However, another consideration, which may result in a limiting decay time prior to fuel handling, is the impact of decay heat on the spent fuel pool cooling requirements described in Reference 4. Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.
APPLICABILITY	LCO 3.9.7 is applicable when moving irradiated fuel assemblies within containment. The LCO ensures a sufficient level of water is present in the refueling cavity to minimize the radiological consequences of a fuel handling accident in containment. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.14, "Spent Fuel Pool Water Level."
ACTIONS	A.1 With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of irradiated fuel movement shall not preclude completion of movement of a fuel assembly to a safe position.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.7.1 Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. Regulatory Guide 1.183, July 2000. 2. UFSAR, Section 15.7.4. 3. 10 CFR 50.67. 4. NUREG-0800, Section 9.1.3.

BASES

This page intentionally left blank.