BASES

for

Improved Technical Specifications

Vogtle Units 1 and 2

September 25, 1996

Unless noted otherwise, all of the pages in the Units 1 and 2 Bases are effective per Revision 0 as of January 23,1997. The latest revised page is REVISION 82.

PAGE	REVISION
i	46
ii	3 - 9/06
iii	2 - 3/05
iv	1 - 3/99
v	82
B 2.1.1-5	16
B 2.1.1-6	16
B 2.1.1-7	1 - 6/03
B 2.1.2-3	16
B 2.1.2-4	16
B 2.1.2-5	16
B 3.0-1	49
B 3.0-2	58
B 3.0-3	58
B 3.0-4	46
B 3.0-5	46
B 3.0-6	46
B 3.0-7	46
B 3.0-8	46
B 3.0-9	82
B 3.0-10	82
B 3.0-11	82
B 3.0-12	82
B 3.0-13	82
B 3.0-14	82
B 3.0-15	82
B 3.0-16	82
B 3.0-17	82
B 3.0-18	82
B 3.0-19	82
B 3.0-20	82
B 3.0-21	82
B 3.0-22	82
B 3.1.1-4	3 - 6/05
B 3.1.1-5	1 - 6/05
B 3.1.1-6	14
B 3.1.2-3	1 - 10/01
B 3.1.2-5	40
B 3.1.2-6	14
B 3.1.3-1	67
B 3.1.3-2	67

PAGE	REVISION
B 3.3.4-7	40
B 3.3.5-1	1 - 10/07
B 3.3.5-2	1 - 3/00
B 3.3.5-3	2 - 10/07
B 3.3.5-7	20
B 3.3.5-8	26
B 3.3.5-9	26
B 3.3.6-2	2 - 10/01
B 3.3.6-3	1 - 3/99
B 3.3.6-4	1 - 3/99
B 3.3.6-5	1 - 3/99
B 3.3.6-6	1 - 3/99
B 3.3.6-7	14
B 3.3.6-8	14
B 3.3.6-9	20
B 3.3.6-10	20
B 3.3.6-11	14
B 3.3.7-2	1 - 10/01
B 3.3.7-13	14
B 3.3.7-14	20
B 3.3.7-15	26
B 3.3.7-16	26
B 3.3.8-1	2 - 10/01
B 3.3.8-2	3 - 6/05
B 3.3.8-3	20
B 3.4.1-3	1 - 10/01
B 3.4.1-5	14
B 3.4.1-6	14
B 3.4.1-7	14
B 3.4.2-2	1 - 10/01
B 3.4.2-3	40
B 3.4.3-1	80
B 3.4.3-2	0
B 3.4.3-3	80
B 3.4.3-4	80
B 3.4.3-5	0
B 3.4.3-6	0
B 3.4.3-7	14
B 3.4.3-8	1 - 3/05
B 3.4.4-2	2 - 9/06
B 3.4.4-3	14
B 3.4.4-4	14
B 3.4.5-1	40
B 3.4.5-2	40
B 3.4.5-3	40
B 3.4.5-4	40

PAGE	REVISION
B 3.4.12-11	2 - 3/05
B 3.4.12-12	47
B 3.4.12-13	40
B 3.4.12-14	39
B 3.4.13-2	79
B 3.4.13-3	79
B 3.4.13-4	79
B 3.4.13-5	79
B 3.4.13-6	79
B 3.4.13-7	79
B 3.4.14-2	26
B 3.4.14-4	38
B 3.4.14-5	38
B 3.4.14-6	47
B 3.4.14-7	39
B 3.4.15-1	19
B 3.4.15-2	19
B 3.4.15-3	19
B 3.4.15-4	19
B 3.4.15-5	19
B 3.4.15-6	19
B 3.4.15-7	38
B 3.4.15-8	38
B 3.4.15-9	38
B 3.4.16-3	1 - 10/01
B 3.4.16-4	40
B 3.4.16-5	14
B 3.4.16-6	14
B 3.4.17-1	0 - 9/06
B 3.4.17-2	28
B 3.4.17-3	23
B 3.4.17-4	0 - 9/06
B 3.4.17-5	28
B 3.4.17-6	28
B 3.4.17-7	28
B 3.5.1-1	1 - 11/98
B 3.5.1-2	1 - 11/98
B 3.5.1-4	1 - 10/01
B 3.5.1-6	48
B 3.5.1-7	48
B 3.5.1-8	14
B 3.5.1-9	48
B 3.5.2-1	1 - 3/02
B 3.5.2-2	61
B 3.5.2-3	78
B 3.5.2-5	37

PAGE	REVISION
B 3.7.11-7	38
B 3.7.12-1	1 - 11/08
B 3.7.12-2	1 - 11/08
B 3.7.12-3	1 - 11/08
B 3.7.12-4	1 - 11/08
B 3.7.12-5	2 - 11/08
B 3.7.13-2	2 - 10/01
B 3.7.13-3	1 - 5/01
B 3.7.13-4	38
B 3.7.13-5	38
B 3.7.13-6	38
B 3.7.14-1	1 - 3/02
B 3.7.14-2	2 - 3/02
B 3.7.14-3	48
B 3.7.14-4	48
B 3.7.14-5	48
B 3.7.15-1	31
B 3.7.15-3	31
B 3.7.16-2	1 - 10/01
B 3.7.16-3	14
B 3.7.17-1	3 - 9/05
B 3.7.17-2	3 - 9/05
B 3.7.17-3	3 - 9/05
B 3.7.17-4	3 - 9/05
B 3.7.17-5	14
B 3.7.17-6	3 - 9/05
B 3.7.18-1	3 - 9/05
B 3.7.18-2	3 - 9/05
B 3.7.18-3	4 - 9/05
B 3.8.1-1	57
B 3.8.1-3	1 - 10/01
B 3.8.1-5	2 - 6/05
B 3.8.1-6	77
B 3.8.1-7	77
B 3.8.1-8	77
B 3.8.1-9	77
B 3.8.1-10	77
B 3.8.1-11	77
B 3.8.1-12	77
B 3.8.1-13	77
B 3.8.1-14	77
B 3.8.1-15	77
B 3.8.1-16	77
B 3.8.1-17	77
B 3.8.1-18	77
B 3.8.1-19	77

PAGE	REVISION
B 3.8.6-1	2 - 3/05
B 3.8.6-2	1 - 3/05
B 3.8.6-3	1 - 3/05
B 3.8.6-4	1 - 3/05
B 3.8.6-5	14
B 3.8.6-6	14
B 3.8.6-7	14
B 3.8.6-8	14
B 3.8.6-9	14
B 3.8.7-1	29
B 3.8.7-2	1 - 9/97
B 3.8.7-3	1 - 10/01
B 3.8.7-4	48
B 3.8.7-5	60
B 3.8.7-6	60
B 3.8.7-7	60
B 3.8.8-1	1 - 10/01
B 3.8.8-2	2 - 4/09
B 3.8.8-3	1 - 9/97
B 3.8.8-4	14
B 3.8.9-2	1 - 10/01
B 3.8.9-5	48
B 3.8.9-6	48
B 3.8.9-7	60
B 3.8.9-8	60
B 3.8.9-9	60
B 3.8.9-10	48
B 3.8.9-11	48
B 3.8.10-1	1 - 10/01
B 3.8.10-2	2 - 4/09
B 3.8.10-3	1 - 9/97
B 3.8.10-4	1 - 9/97
B 3.8.10-6	14
B 3.9.1-3	40
B 3.9.1-4	40
B 3.9.2-2	1 - 10/01
B 3.9.2-4	14
B 3.9.3-1	3 - 4/09
B 3.9.3-2	1 - 4/09
B 3.9.3-3	14
B 3.9.4-1	1 - 9/00
B 3.9.4-2	1 - 3/99
B 3.9.4-3	31
B 3.9.4-4	31
B 3.9.4-5	41
B 3.9.4-6	41

(continued)

(continued)

(continued)

(continued)

LIST OF TABLES

LIST OF FIGURES

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 on the limiting fuel rods 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.

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.

(continued)

BASES

BACKGROUND (continued)

The proper functioning of the Reactor Protection System (RPS) and main steam safety valves 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. 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.

In meeting the DNB design criterion, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, and computer codes must be considered. As described in the FSAR, the effects of these uncertainties have been statistically combined with the correlation uncertainty to determine design limit DNBR values that satisfy the DNB design criterion. The Vantage 5 fuel is analyzed using the WRB-2 correlation with design limit DNBR values of 1.24 and 1.23 for the typical and thimble cells, respectively. The Lopar fuel is analyzed using the WRB-1 correlation with design limit DNBR values of 1.23 and 1.22 for the typical and thimble cells, respectively.

Additional DNBR margin is maintained by performing the safety analyses to a higher DNB limit. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility.

The Reactor Trip System setpoints (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

(DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the following functions:

a. High pressurizer pressure trip;

b. Low pressurizer pressure trip;

c. Overtemperature ΔT trip;

d. Overpower ΔT trip;

e. Power Range Neutron Flux trip;

f. Reactor Coolant Flow trips (including undervoltage and underfrequency of the reactor coolant pump buses); and

g. Main steam safety valves.

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the ΔT measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

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 (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The curves provided in Figure B 2.1.1-1 show the loci of points of THERMAL POWER (NI-0041, NI-0042, NI-0043, NI-0044, TDI-0411A, TDI-0421A, TDI-0431A, TDI-0441A), RCS Pressure (PI-0455A, B, and C, PI-0456, PI-0456A, PI-0457, PI-0457A, PI-0458, and PI-0458A), and average temperature (TI-0412, TI-0422, TI-0432, TI-0442) for which the minimum DNBR is not less than the safety analyses limit, that fuel

(continued)

BASES

SAFETY LIMITS (continued)

centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNBR correlation.

The curves are based on enthalpy hot channel factor limits provided in the COLR. The dashed line of Figure B 2.1.1-1 shows an example of a limit curve at 2235 psig. In addition, it illustrates the various RPS functions that are designed to prevent the unit from reaching the limit.

The SL is higher than the limit calculated when the AFD is within the limits of the $F_1(\Delta I)$ function of the overtemperature ΔT reactor trip. When the AFD is not within the tolerance, the AFD effect on the overtemperature ΔT reactor trips will reduce the setpoints to provide protection consistent with the reactor core SLs (Refs. 3 and 4).

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 main steam safety valves 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, "Reactor Trip System (RTS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

Section 2.2, SL Violations, provides the Required Actions to be taken in response to a violation of Safety Limits. The bases for the Required Actions of Section 2.2 applicable to a violation of the reactor core SLs are discussed below.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.1

If the reactor core 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.

(continued)

BASES (continued)

REFERENCES	1.	10 CFR 50, Appendix A, GDC 10.
	2.	FSAR, Section 7.2.
	3.	WCAP-8746-A, March 1977.
	4.	WCAP-9272-P-A, July 1985.

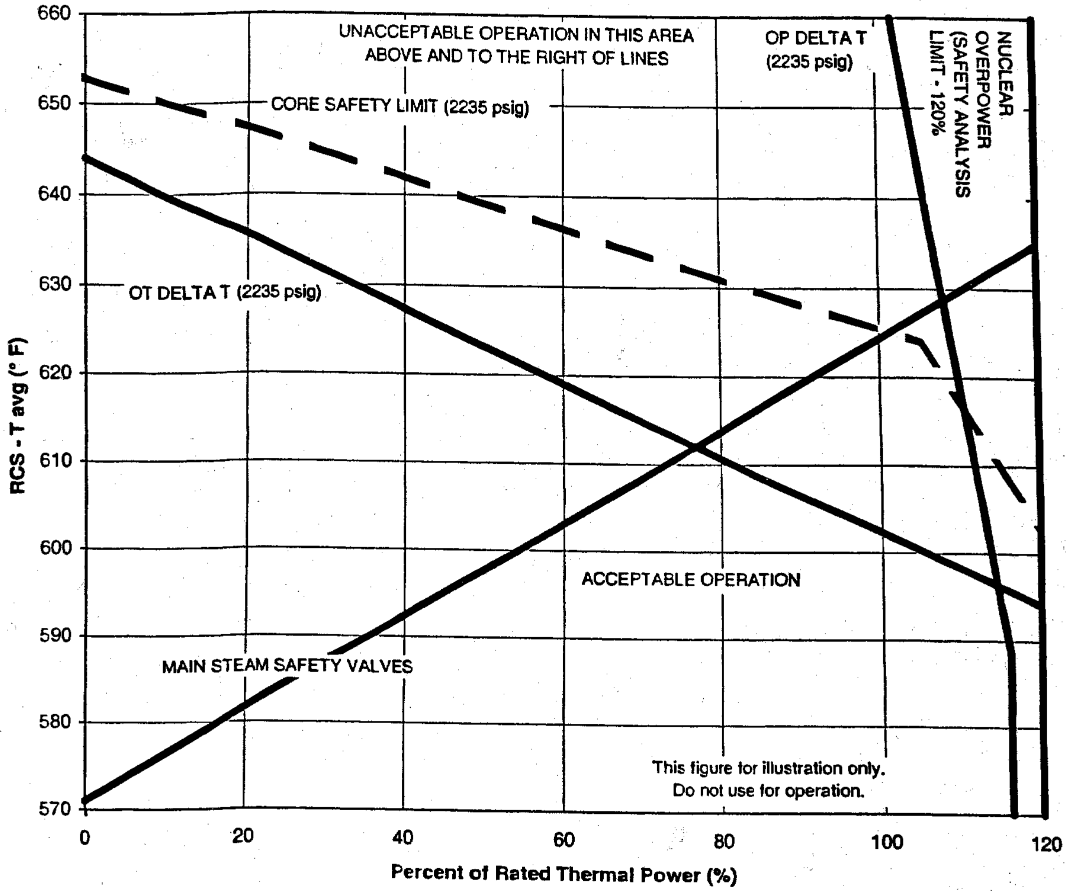

Figure B 2.1.1-1 (page 1 of 1)
REACTOR CORE SAFETY LIMITS VS. BOUNDARY OF PROTECTION

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 shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure 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 safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

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

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

a. Pressurizer power operated relief valves (PORVs);

b. Main steam atmospheric relief valves;

c. Steam Dump System;

d. Rod Control System;

e. Pressurizer Level Control System; or

f. Pressurizer Spray System.

SAFETY LIMITS

The maximum transient pressure (PI-0408, PI-0418, PI-0428, PI-0438) allowed in the RCS pressure vessel under the ASME

(continued)

BASES

SAFETY LIMITS (continued)

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 the RCS pressure SL 2.2.2 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.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.2.2

If the RCS pressure SL 2.2.2 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. 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.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

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, Article IWB-5000.
4. 10 CFR 100.
5. FSAR, 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.

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

(continued)

BASES

LCO 3.0.2 (continued)

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 Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

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. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

(continued)

BASES (continued)

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 combination of Conditions stated in the ACTIONS can be made that exactly 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 ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 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 plant 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.

(continued)

BASES

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 Specification 3.0.3 allow 37 hours 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.

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 appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.15, "Fuel Storage Pool Water Level." LCO 3.7.15 has

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BASES

LCO 3.0.3 (continued)

an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.15 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 3.7.15 of "Suspend movement of irradiated fuel assemblies in the fuel storage 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 3.0.4a, LCO 3.0.4b, or LCO 3.0.4c.

LCO 3.04a 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 in 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.

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BASES

LCO 3.0.4 (continued)

LCO 3.0.4b 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 be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4b, 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 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.” Both documents provide general guidance for conducting the risk assessment, such as quantitative and qualitative guidelines for establishing risk management actions and example risk management actions. They also include actions to plan and conduct other activities in a manner to control overall risk, increase risk awareness by shift and management personnel, reduce the duration of the condition, minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determine that the proposed 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 abandoning the Applicability.

LCO 3.0.4b 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 3.0.4b risk assessments do not have to be documented.

(continued)

BASES

LCO 3.0.4 (continued)

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and 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 3.0.4b 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 3.0.4b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4b by stating that LCO 3.0.4b is not applicable.

LCO 3.0.4c 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 that LCO 3.0.4c 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 ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4b usually only consider systems and components. For this reason, LCO 3.0.4c is typically applied to Specifications which describe values and parameters (e.g., RCS Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

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, 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, the LCO is met, or the unit is not within the Applicability of the Technical Specification.

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BASES

LCO 3.0.4 (continued)

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.

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 Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate:

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

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed SRs. 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 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 Rector 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. 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 an SR on another channel in

(continued)

BASES

LCO 3.0.5 (continued)

the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of an SR 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 supported systems that have a support system 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' LCOs' 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.

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.

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BASES

LCO 3.0.6 (continued)

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.

The following examples use Figure B 3.0-1 to illustrate loss of safety function conditions that may result when a TS support system is inoperable. In this figure, the fifteen systems that comprise Train A are independent and redundant to the fifteen systems that comprise Train B. To correctly use the figure to illustrate the SFDP provisions for a cross train check, the figure establishes a relationship between support and supported systems as follows: the figure shows System 1 as a support system for System 2 and System 3; System 2 as a support system for System 4 and System 5; and System 4 as a support system for System 8 and System 9. Specifically, a loss of safety function may exist when a support system is inoperable and:

a. A system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1),

b. A system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2), or

c. A system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

For the following examples, refer to Figure B 3.0-1.

<u>EXAMPLE B 3.0.6-1</u>

If System 2 of Train A is inoperable, and System 5 of Train B is inoperable, a loss of safety function exists in Systems 5, 10, and 11.

<u>EXAMPLE B 3.0.6-2</u>

If System 2 of Train A is inoperable, and System 11 of Train B is inoperable, a loss of safety function exists in System 11.

<u>EXAMPLE B 3.0.6-3</u>

If System 2 of Train A is inoperable, and System 1 of Train B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10 and 11.

(continued)

BASES

LCO 3.0.6 (continued)

If an 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.

EXAMPLES

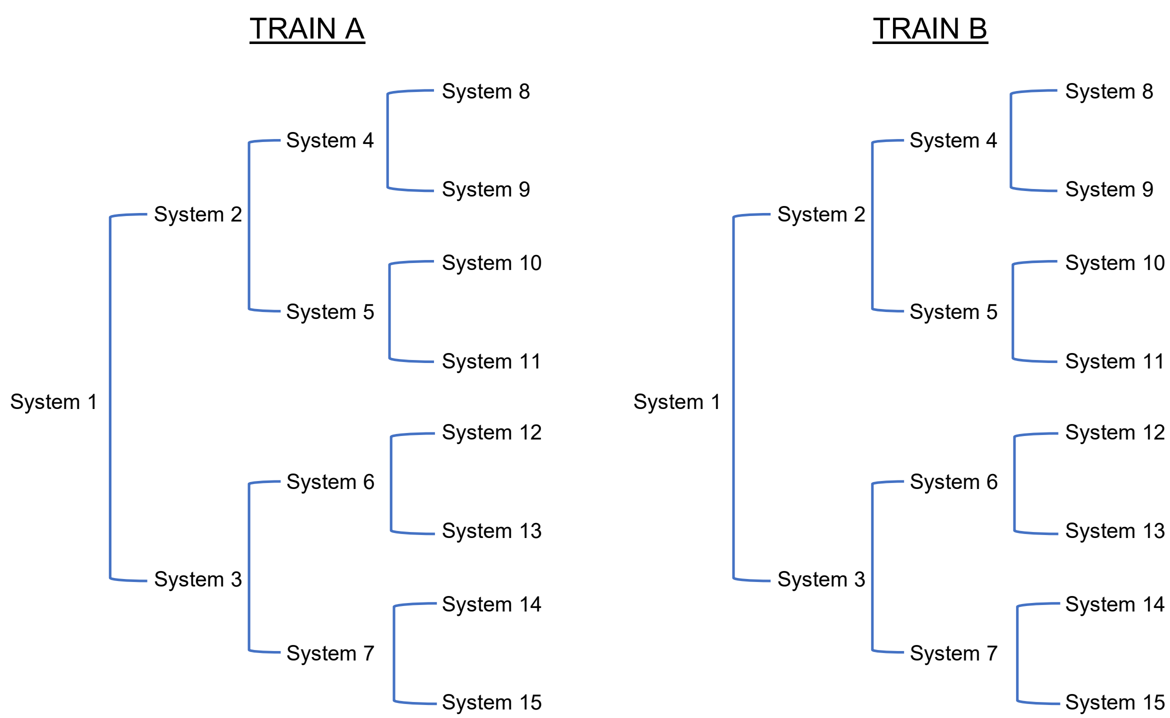

Figure B 3.0-1 Configuration of Trains and Systems

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperablilty of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When a loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable

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BASES

LCO 3.0.6 (continued)	instrumentation, or loss of pump suction source due to low tank level), the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately address the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.
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. Test Exception LCO 3.1.8 allows specified Technical Specification requirements to be changed to permit performance of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these Technical Specifications. Unless otherwise specified, all the other Technical Specification 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 the Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the Technical Specification. Compliance with the Test Exception LCO is optional. A special operation may be performed either under the provisions of the Test Exception LCO or under the other applicable Technical Specification requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.
LCO 3.0.8	LCO 3.0.8 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 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. If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected support system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

(continued)

BASES

LCO 3.0.8 (continued)

LCO 3.0.8.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 3.0.8.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 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 and due to the availability of the redundant train of the supported system.

LCO 3.0.8.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 3.0.8.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 3.0.8 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 3.0.8 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 3.0.9

This LCO is provided to clarify the unit applicability of the LCOs and associated ACTION requirements, especially with respect to systems or components that are common to both units.

In the LCOs and Specifications, parentheses and footnotes are used to specifically identify the common systems to which individual LCOs and Specifications apply. They are considered an integral part of the applicable LCOs and Specifications and compliance with respect to the systems or components is required. In addition, parentheses and footnotes are used to identify requirements specific to one unit, and are considered an integral part of the LCOs and Specifications with which compliance is required.

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BASES

LCO 3.0.9 (continued)

In the Bases, instrument loop numbers are stated in parentheses and are provided as information only, for the purpose of assisting the TS user. Compliance with the applicable LCO and Specifications may not be a requirement for the instrument loop stated within parentheses unless the stated loop is the method by which the unit is maintained in compliance with the applicable LCOs and Specifications.

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(s) 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 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 to 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 OPERABILITY (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:

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BASES

LCO 3.0.10 (continued)

- 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, RG 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, Revision 4A, “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 barriers are unable to perform their related support functions(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.

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BASES

LCO 3.0.10 (continued)

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 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 3.0.4 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 a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

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

(continued)

BASES

SR 3.0.1 (continued)

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 plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

When a Section 5.5 “Programs and Manuals,” specification states that the provisions of SR 3.0.2 are applicable, a 25% extension of the testing interval, whether stated in the specification or incorporated by reference, is permitted.

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. The requirements of regulations take precedence over the TS. Examples of where SR 3.0.2 does not apply are the Containment Leakage Rate Testing Program required by 10 CFR 50, Appendix J, and the inservice testing of pumps and valves in accordance with applicable American Society of Mechanical Engineers Operation and Maintenance Code, as required by 10 CFR 50.55a. These programs establish testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot, in and of themselves, extend a test interval specified in the regulations directly or by reference.

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

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BASES

SR 3.0.2 (continued)

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.

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.

When a Section 5.5 “Programs and Manuals,” specification states that the provisions of SR 3.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 3.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 3.0.2 if invoked by the Section 5.5 specification).

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.

(continued)

BASES

SR 3.0.3 (continued)

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.

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. 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,

(continued)

BASES

SR 3.0.3 (continued)

"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.

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 a Surveillance not being met in accordance with LCO 3.0.4.

(continued)

BASES

SR 3.0.4 (continued)

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) is 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 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, 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.

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 assembly 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 control assemblies 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 can 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.

(continued)

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes a 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 scram.

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 Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and < 200 cal/gm average fuel pellet enthalpy at the hot spot for the rod ejection accident); and

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

The most limiting accident for the MODES 1 and 2 SDM requirements is a guillotine break of a main steam line inside containment initiated at the end of core life with RCS average temperature at no-load operating temperature, 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 guillotine break of a main steam line inside containment initiated at the end of core life at no-load operating temperature. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus

(continued)

APPLICABLE SAFETY ANALYSES (continued)

terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, the MSLB analysis bounds the post trip return to power, and therefore, there is adequate protection to ensure that the specified acceptable fuel design limits are not exceeded for this transient.

The most limiting event in MODES 3, 4, and 5 is a boron dilution at BOL, when critical boron concentration is highest. In the boron dilution analysis, 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. In the analysis of this accident, the minimum SDM specified in the Core Operating Limits Report (COLR) is required to allow the operator 15 minutes from the initiation of the Source Range High Flux at Shutdown Alarm to total loss of SDM.

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

a. An uncontrolled rod withdrawal from subcritical or low power condition; and

b. Rod ejection.

Each of these events is discussed below.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or a high pressurizer pressure trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The ejection of a control rod rapidly adds 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 a rod also produces a time dependent redistribution of core power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

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 100, "Reactor Site Criteria," limits (Ref. 4). 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. The required SDM is specified in the COLR.

APPLICABILITY

In 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 MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits."

ACTIONS

The ACTIONS table is modified by a Note prohibiting transition to a lower MODE within the Applicability. LCO 3.0.4 already prohibits entry into MODE 5 from MODE 6, MODE 4 from MODE 5 and into MODE 3 from MODE 4 when SDM requirements are not met.

(continued)

BASES

ACTIONS (continued)

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 important to raise the boron concentration of the RCS as soon as possible, the flowpath of choice would utilize a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. However, the operator should borate with the best source available for the plant conditions.

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 cycle when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% Δk/k must be recovered and a boration flow rate of 30 gpm, it is possible to increase the boron concentration of the RCS by 133 ppm in approximately 55 minutes using a boric acid solution of 7000 ppm. If a boron worth of 7.5 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% Δk/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 MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. FSAR, Subsection 15.4.9.

3. FSAR, Subsection 15.4.6.

4. 10 CFR 100.

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 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 (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the

(continued)

BASES

BACKGROUND (continued)	calculational models used to generate the safety analysis are adequate. 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 RTP and moderator 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.

(continued)

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 cycle 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).

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

(continued)

BASES

LCO (continued)

reactivity balance of ± 1% Δk/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% Δk/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).

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

(continued)

ACTIONS

A.1 and A.2 (continued)

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.

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

(continued)

BASES

ACTIONS

B.1 (continued)

LCO 3.1.1 Required Action A.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 as an initial check on core conditions and design calculations at BOL. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 28, and GDC 29.
2. FSAR, Chapter 15.

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 surveillances. Reload cores are designed so that the beginning of cycle life (BOL) MTC is less than zero when THERMAL POWER is at RTP. 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 BOL within the range analyzed in the plant accident analysis. The end of cycle 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 FSAR accident and transient analyses.

(continued)

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 verification 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.

The FSAR, Chapter 15 (Ref. 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 (increase in heat removal by the secondary system).

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 at 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.

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.

The conditions of the LCO are ensured through surveillances.

(continued)

BASES

LCO (continued)

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. 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.

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 CONTROL ROD assembly or group withdrawal) 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. 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 surveillance and computing the required 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

(continued)

BASES

ACTIONS

A.1 (continued)

longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 3 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 plant 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 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 verification of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1 (continued)

If required, the BOL MTC can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In 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.

SR 3.1.3.2 is modified by four Notes that include the following requirements:

a. The 300 ppm Surveillance limit must be verified within 7 EFPD after reaching the equivalent of an equilibrium RTP ARO boron concentration of 300 ppm. Seven effective full power days after reaching an equivalent boron concentration of 300 ppm are sufficient to ensure that the EOL limit will not be exceeded.

b. SR 3.1.3.2 is not required to be performed by measurement provided that the benchmark criteria in WCAP-13749-P-A (Ref. 4) are satisfied and the Revised Predicted MTC satisfies the 300 ppm surveillance limit specified in the COLR.

c. 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 effective full power days is sufficient to avoid exceeding the EOL limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

d. 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.

REFERENCES

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

2. FSAR, Chapter 15.

3. WCAP 9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

4. WCAP-13749-P-A, “Safety Evaluation Supporting the Conditional Exemption of the Most Negative EOL Moderator Temperature Coefficient Measurement,” March 1997.

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," and GDC 26, "Reactivity Control System Redundancy and Capability" (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 rod to become inoperable or to become misaligned from its group. Control 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, control 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 control 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 ⅝ inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists

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BASES

BACKGROUND (continued)

of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and five shutdown banks. All control banks contain two rod groups, two shutdown banks contain two rod groups, and the remaining three shutdown banks contain one rod group.

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 position of maximum withdrawal, 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, which are 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 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 ± ⅝ inch). 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 control rod position, but at a lower precision than the step counters. This system is based on inductive analog

(continued)

BASES

BACKGROUND (continued)

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. However, the magnetic drive rod concentrates the magnetic lines of flux developed in the coil resulting in a change in coil output voltage when the shaft is close to it. This provides a ± 4 step accuracy with all coils operable. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the DRPI will go on half accuracy (System A failure = +10, -4 steps and System B failure = -10, +4 steps) with an effective coil spacing of 7.5 inches, which is 12 steps. The resolution of the rod position indicator channel is ± 5 percent of span (± 7.5 in. or ± 12 steps). Deviation of any RCCA from its group by 10 percent of span (15 inches or 24 steps) will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 5 percent of span (12 steps). Therefore, since indication from one system is sufficient to maintain alignment within 24 steps, operation with one system (in the event of failure of the other) is acceptable.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control 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. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

sufficient reactivity worth is held in the control 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. 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 of a completely withdrawn single rod from a bank inserted to its insertion limit. 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 also fully withdrawn (Ref. 3).

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 control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy 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 control 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 using core power distribution information. 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).

(continued)

BASES (continued)

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) are separate from the alignment requirements which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

The rod OPERABILITY (i.e., trippability) requirement is satisfied provided that the rod will fully insert in the required rod drop time assumed in the safety analyses. Rod control malfunctions that result in the inability to move a rod (e.g., rod lift coil failures), but that do not impact trippability, do not result in rod inoperability. However, where rod(s) are not moving, the rod(s) must be considered untrippable unless there is verification that a rod control system failure is preventing rod motion. If the rod control system is demanding motion properly and no motion occurs, the rod is considered untrippable (i.e., inoperable).

The requirement to maintain the rod alignment to within plus or minus 12 steps of their group step counter demand position is conservative. The safety analysis assumes a total misalignment from fully withdrawn to fully inserted. When required, core power distribution information may be used to determine rod position and verify the rod alignment requirement of this LCO is met.

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 a self-sustaining chain reaction ($K_{eff} \geq 1$) occurs, 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, with no self-sustaining chain reaction. 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 during refueling.

(continued)

BASES (continued)

ACTIONS

A.1.1 and A.1.2

When one or more rods are 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, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration to restore SDM.

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

A.2

If the untrippable rod(s) cannot be restored to OPERABLE status, the plant 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

With a misaligned but trippable rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

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 inserted to approximately 100 to 115 steps.

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

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BASES

ACTIONS

B.1.1 and B.1.2 (continued)

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.

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

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned shortly after the misalignment, local xenon redistribution during this short interval will not be significant, and operation in compliance with the LCO may proceed without further restriction.

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." The Completion Time of Required Action B.2 gives the operator sufficient time to adjust the rod positions in an orderly manner or subsequently reduce power if the rod alignment cannot be restored to within the LCO limits shortly after the misalignment.

For continued operation with a misaligned rod, reactor power must be reduced, SDM must periodically be verified within limits, hot channel factors (FQ(Z) and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be reevaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 3). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

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.

(continued)

BASES

ACTIONS

B.2, B.3, B.4, and B.5 (continued)

A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP 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 core power distribution information 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 Event 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.

The following accident analyses require reevaluation for continued operation with a misaligned rod.

RCCA Insertion Characteristics
RCCA Misalignment
Decrease in Reactor Coolant Inventory

- Inadvertent Opening of a Pressurizer Safety or Relief Valve
- Break in Instrument Line or Other Lines From Reactor Coolant Pressure Boundary That Penetrates Containment
- Loss-of-Coolant-Accidents

Increase in Heat Removal by the Secondary System (Steam System Piping Rupture) Spectrum of RCCA Ejection Accidents.

C.1

When Required Actions 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

(continued)

BASES

ACTIONS

C.1 (continued)

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.

D.1.1 and D.1.2

More than one control rod becoming misaligned (but trippable) from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM 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 required for potential xenon redistribution, the low probability of an accident to provide negative reactivity, as described in the Bases or LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time 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.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

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.

SR 3.1.4.2

Exercising each individual control rod provides 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, 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 from the physical fully withdrawn position 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 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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.3 (continued)

control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 551°F (TI-0412, TI-0422, TI-0432, TI-0442) to simulate a reactor trip under actual conditions.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10 and GDC 26.
2. 10 CFR 50.46.
3. FSAR, Subsection 15.4.3.

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 Capability," 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 rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and five shutdown banks. Three shutdown banks consist of a single group. 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 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

(continued)

BASES

BACKGROUND (continued)

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 fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks 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.

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 rod bank insertion limits and inoperability or misalignment is that:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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).

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 is modified by a Note indicating 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. The applicability in MODE 2 begins at initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. 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 banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. 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.

(continued)

BASES (continued)

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 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 insertion limits for reasons other than Condition A, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their 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 plant to remain in an unacceptable condition for an extended period of time.

(continued)

BASES

ACTIONS (continued)	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 the reactivity of the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28. 2. 10 CFR 50.46. 3. FSAR, Subsection 15.4.3.

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 Capability," and 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 rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and five shutdown banks. Three shutdown banks consist of a single group. 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 banks operate with a predetermined amount of position overlap, in order to approximate a linear relation between rod worth and rod position (integral rod worth). To achieve this approximately linear relationship, the control banks are withdrawn and operated in a predetermined sequence. The automatic control system controls reactivity by moving the control banks in sequence within analyzed ranges.

(continued)

BASES

BACKGROUND (continued)

The control bank insertion limits are specified in the COLR. An example is provided for information only in Figure B 3.1.6-1. The control banks are required to be at or above the insertion limit lines.

Figure B 3.1.6-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. Another parameter that is of importance in the safety analyses is the control bank tip-to-tip distance. This is the distance between the bottom of the control rods (tips) in two control banks as they travel together. For example, if the all-rods-out (ARO) position is 228 steps, and the tip-to-tip distance is 115 steps, then the overlap is 113 steps. The safety analyses are based on maintaining a constant tip-to-tip distance. Since the ARO position can be varied, the amount of overlap will correspondingly vary. The distance between the insertion limit lines is the tip-to-tip distance. The tip-to-tip distance also determines the position of a control bank at which the next bank in the sequence will begin to move on withdrawal. For example, with a tip-to-tip difference of 115 step Control Bank B will begin to move from the fully inserted position when Control Bank A is at 115 steps.

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

(continued)

BASES

BACKGROUND (continued)

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 subject 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.

APPLICABLE SAFETY ANALYSES

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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion 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 banks sequence, overlap, and physical insertion, 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 is modified by a Note indicating 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 sequence, overlap, and physical insertion 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 MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

(continued)

BASES (continued)

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 shutdown 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 MODES 1 and 2 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.

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.

(continued)

BASES

ACTIONS

B.1.1, B.1.2, B.2, C.1.1, C.1.2, and C.2 (continued)

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 plant 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 plant must be brought to MODE 3, 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 3.1.6.1

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

Among the factors that impact the estimated critical position (ECP) is Xenon concentration, which varies with time, either increasing or decreasing depending on the amount of time since the trip occurred. The 4 hour limit within which the ECP must be verified within the insertion limits ensures that changes in Xenon concentration will be limited and, hence, it ensures that criticality will not occur with control rods outside of the insertion limits due to Xenon decay.

SR 3.1.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the insertion limit monitor becomes inoperable, verification of the control bank position at the specified Frequency is sufficient to detect control banks that may be approaching the insertion limits.

(continued)

BASES

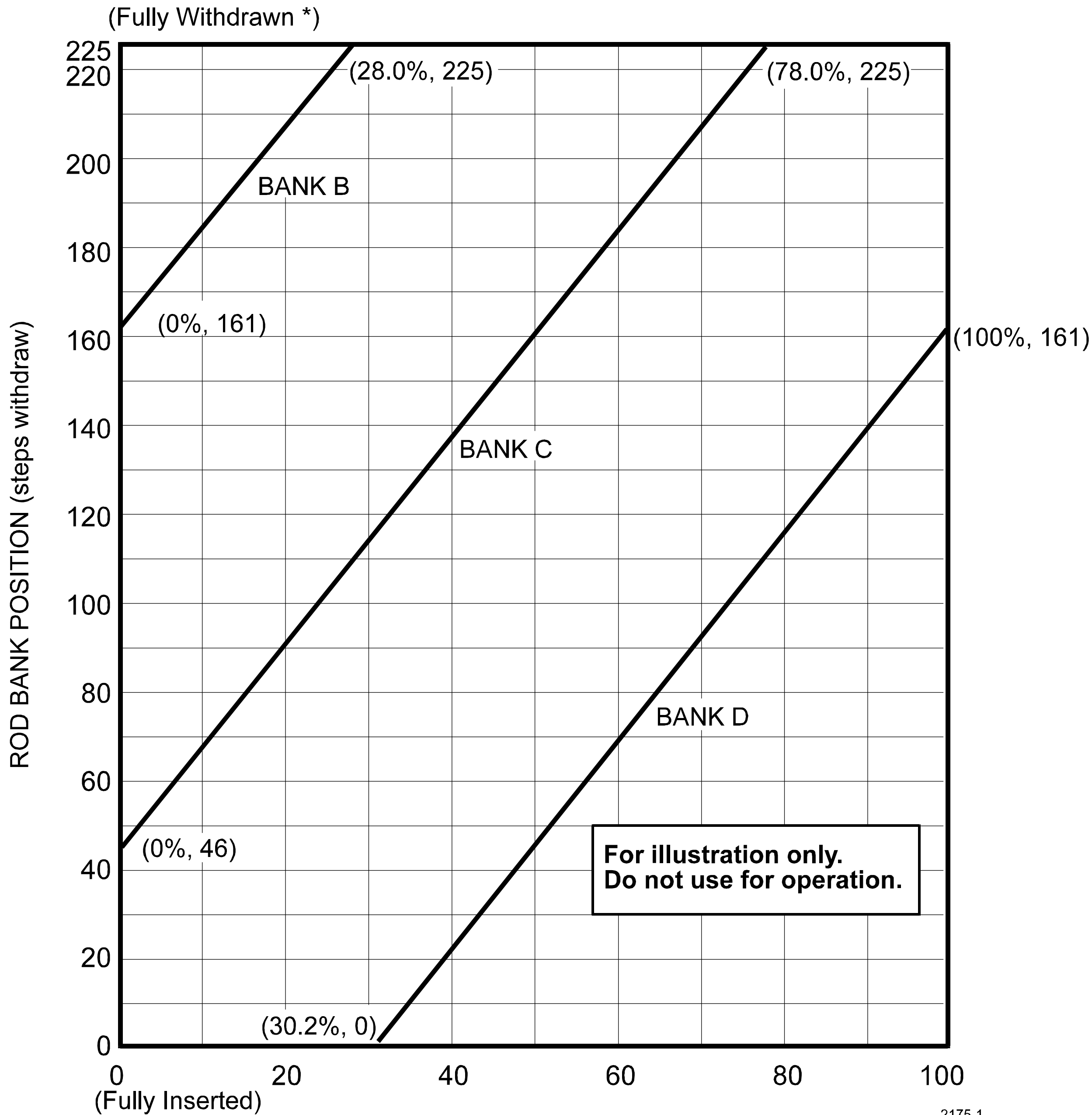
SURVEILLANCE REQUIREMENTS (continued)

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. This surveillance is accomplished from the control room by verifying via the demand step counters that, for the plant conditions at that time, the sequence and overlap limits are satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. For the purposes of this surveillance, "fully withdrawn" is the defined all rods out (ARO) position.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10, GDC 26, and GDC 28.
2. 10 CFR 50.46.
3. FSAR, Subsection 15.4.3.



* Fully withdrawn shall be the condition where control rods are at a position within the interval ≥225 and ≤231 steps withdrawn.

Note: The rod bank insertion limits are based on the control bank withdrawal sequence A,B,C, D and a control bank tip-to-tip distance of 115 steps.

Figure B 3.1.6-1 (page 1 of 1)
Rod Bank Insertion Limits vs. Thermal Power

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 shutdown and control 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 shutdown or control 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. Limits on rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the core is maintained within the power distribution and reactivity limits defined by the design power peaking and SDM limits.

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 rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods is determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called

(continued)

BASES

BACKGROUND (continued)

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 ± ⅝ inch). 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 6 steps. However, the magnetic drive rod concentrates the magnetic lines of flux developed in the coil, resulting in a change in coil output voltage when the shaft is close to it. This provides a ± 4 step accuracy with all coils operable. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus, if one system fails, the DRPI will go on half accuracy (System A failure = +10, - 4 steps and System B failure = -10, +4 steps) with an effective coil spacing of 7.5 inches, which is 12 steps. The resolution of the rod position indicator channel is ± 5 percent of span (± 7.5 in. or ± 12 steps). Deviation of any RCCA from its group by 10 percent of span (15 inches or 24 steps) will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 5 percent of span (12 steps). Therefore, since indication from one system is sufficient to maintain alignment within 24 steps, operation with one system (in the event of failure of the other) is acceptable.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 assumed group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (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 Digital Rod Position Indication System be OPERABLE for each shutdown and control rod and that the Demand Position Indication System be OPERABLE for each rod group. This operability is demonstrated through the performance of SR 3.1.7.1, which verifies that the digital rod position indication for each rod is within 12 steps of the applicable group demand position for the full range of rod travel. Additional verification that DRPI is within 12 steps of the demand position indication occurs in accordance with LCO 3.1.4 and SR 3.1.4.1.

This requirement ensures 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

(continued)

BASES

APPLICABILITY (continued)

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 rod position indicator and each inoperable demand position indicator. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

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

When one DRPI channel per group in one or more groups fails, the position of the rod may still be determined indirectly by using core power distribution information. The Required Action may also be satisfied by ensuring at least once per 8 hours that F_Q satisfies LCO 3.2.1, F_{deltaH} satisfies LCO 3.2.2, and SHUTDOWN MARGIN is within the limits provided in the COLR, provided the non-indicating rods have not been moved. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of C.1 or C.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 by using core power distribution information. Required Action A.2.1 provides an alternative. Required Action A.2.1 requires verification of rod position by using core power distribution information every 31 EFPD, which coincides with the normal frequency to verify core power distribution.

Required Action A.2.1 includes six distinct requirements for verification of the position of rods associated with an inoperable DRPI using core power distribution information:

(continued)

BASES

ACTIONS

A.1, A.2.1, and A.2.2 (continued)

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

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

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 the reactor power is changed, the position of the rod with the inoperable DRPI must be verified.

Required Action A.2.2 states that the inoperable DRPI must be restored to OPERABLE status prior to entering MODE 2 from MODE 3. The repair of the inoperable DRPI must be performed prior to returning to power operation following a shutdown.

A.3

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors.

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 above.

(continued)

BASES

ACTIONS (continued)

B.1 and B.4

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 a 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 within inoperable DRPI. Within 8 hours, the position of the rods with inoperable position indication must be determined using core power distribution information to verify that these rods are still properly positioned, relative to their group positions.

Either the rod positions must be determined within 8 hours, or 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. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions using core power distribution information.

(continued)

BASES

ACTIONS (continued)

D.1.1 and D.1.2

With one or more demand position indicators 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 rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod 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 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 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.

(continued)

BASES (continued)

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.

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

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 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. FSAR, 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 plant. 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 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.

(continued)

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 that may be performed for reload fuel cycles in MODE 2 include:

a. Critical Boron Concentration – Control Rods Withdrawn;

b. Isothermal Temperature Coefficient (ITC); and

c. Control Rod Worth.

These tests are performed in MODE 2 at hot zero power (HZP), and they 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 lead control bank is at or near its fully withdrawn position. HZP is where the core is critical (keff = 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).”

b. 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

(continued)

BASES

BACKGROUND (continued)

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."

c. The Control Rod worth Test is used to measure the reactivity worth of selected control 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 control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This sequence is repeated for the remaining control 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 control banks. The third method, the Boron Endpoint Method, moves the selected control 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 control bank. This sequence is repeated for the remaining control banks. The fourth method is by dynamic insertion (Dynamic Rod Worth Measurement (DRWM). In this method, the core is critical in a near all rods out condition. All rods are withdrawn, and each bank is then inserted into and withdrawn from the core, measuring the worth dynamically. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during 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. 4). 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.

The FSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Tables 14.2.1-1 and 14.2.1-2 summarize the zero, low power, and power tests. Reload fuel cycle PHYSICS TESTS are performed in accordance with Technical Specification requirements, fuel vendor guidelines, and established industry practices. Although these PHYSICS TESTS are generally accomplished within the limits for 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, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 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 ≥ 541°F, and SDM is ≥ the limit 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).

Reference 5 allows special test exceptions (STEs) to be included as part of the LCO that they afect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

(continued)

BASES (continued)

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. THERMAL POWER is maintained ≤ 5 % RTP;

b. RCS lowest loop average temperature is ≥ 541 °F; and

c. SDM is ≥ the limit specified in the COLR.

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

A.1 and A.2

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 plant 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, and 1 hour is a reasonable time frame in which to make a controlled evolution.

(continued)

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 Tavg is < 541°F, the appropriate action is to restore Tavg to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring Tavg to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 541°F could violate the assumptions for accidents analyzed in the safety analyses.

D.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 15 minutes. The Completion Time of 15 minutes is reasonable, based on operating experience, for reaching MODE 3 from MODE 2 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 within 12 hours prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1 (continued)

core protection during the performance of the PHYSICS TESTS. The 12 hour time limit is sufficient to ensure that the instrumentation is OPERABLE shortly before initiating PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ 541°F (TI-0412, TI-0422, TI-0432, and TI-0442) 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

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 reactor operation is relatively steady-state, and the fuel temperature will be changing at the same rate as the RCS.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.3 (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. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.
5. WCAP-11618, including Addendum 1, April 1989.
6. WCAP-13360-P-A, "Westinghouse Dynamic Rod Worth Measurement Technique," January 1996.

B 3.2 POWER DISTRIBUTION LIMITS

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

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 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, 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.

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

$F_Q(Z)$ is measured periodically. These measurements are generally taken with the core at or near steady state conditions.

Using the three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations.

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

Core monitoring and control under non-steady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must 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 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the fission energy input to the fuel will be below 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).

LCO

To ensure that the Heat Flux Hot Channel Factor, $F_Q(Z)$, will remain within limits during steady state operation, $F_Q(Z)$ shall be limited by the following relationships which define the steady state limits:

(continued)

BASES

LCO
(continued)

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

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

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 limits 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. An $F_Q(Z)$ evaluation requires obtaining core power distribution information in MODE 1. From the core power distribution information, the measured value ($F^M{}_Q(Z)$) of $F_Q(Z)$ is obtained. If the core power distribution information is obtained with the Power Distribution Monitoring System (PDMS) then:

$$F_Q(Z) = F^M{}_Q(Z) \times 1.03 \times \left[1.0 + U_Q/100\right]$$

Where 1.03 accounts for fuel manufacturing tolerances and U_Q accounts for PDMS uncertainty as described in Equation 5-19 of Ref. 8. If the core power distribution information is obtained from a flux map using the movable incore detector system with ≥ 44 thimbles, then:

$$F_Q(Z) = F_Q^M(Z) \text{ X } 1.0815$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances (3%) and flux map measurement uncertainty (5%), or when using ≥ 29 and < 44 thimbles:

$$F_Q(Z) = F_Q^M(Z) \text{ x } 1.03 \text{ x } [1.05 + [2.0 \{3–T/(14.5)\}]/100],$$

where 1.03 accounts for fuel manufacturing tolerances with a more conservative flux map measurement uncertainty factor to account for the fewer detector thimbles available, and T is the number of thimbles being used. A bounding measurement uncertainty of 7.0 %, which is based on 29 thimbles, can be used for ≥ 29 and < 44 detector thimbles, if desired. $F_Q(Z)$ evaluations for comparison to the steady

(continued)

LCO (continued)

state limits are applicable in all axial core regions, i.e., from 0 to 100% inclusive.

Because core power distribution information is taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the 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).

The W(Z) curve is provided in the COLR for discrete core elevations. Provided the reload analysis determines that the limiting or peak $F_Q(Z)$ is not located within the upper and lower 8% of the core, $F_Q(Z)$ evaluations for comparison to the transient limits are not required for the following axial core regions, measured in percent of core height:

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

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

The top and bottom 8% of the core are typically 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. It may be necessary to exclude a smaller region or to exclude no region from the evaluation if the location of the limiting $F_Q(Z)$ is in the lower or upper 8% of the core based on the reload analysis.

To account for power distribution transients encountered during normal operation, the transient limits for $F_Q(Z)$ are established utilizing the cycle dependent function W(Z). To ensure that $F_Q(Z)$ will not become excessively high if a normal operational transient occurs, $F_Q(Z)$ shall be limited by the following relationships which define the transient limits:

$$F_Q(Z) \leq \frac{F_Q^{RTP} K(Z)}{P\,W(Z)} \text{ for } P > 0.5$$

$$F_Q(Z) \leq \frac{F_Q^{RTP} K(Z)}{0.5\,W(Z)} \text{ for } P \leq 0.5$$

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during either a large or small break LOCA.

(continued)

BASES

LCO (continued)

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 $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ produces 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.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q(Z)$ exceeds its steady state limit, maintains an acceptable absolute power density. $F_Q(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

A reduction of the Power Range Neutron Flux—High trip setpoints by ≥ 1% of RTP for each 1% by which $F_Q(Z)$ exceeds its steady state 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.

A.3

Reduction in the Overpower ΔT trip setpoints (value of K_4) by ≥ 1% (in %RTP) for each 1% by which $F_Q(Z)$ exceeds its limit, is a conservative

(continued)

ACTIONS

A.3 (continued)

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.

A.4

Verification that $F_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

B.1

If it is found that $F_Q(Z)$ exceeds its specified transient limits, there exists a potential for $F_Q(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limit by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its transient limits within the allowed Completion Time of 2 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factors are not exceeded (Ref. 5). The percent $F_Q(Z)$ exceeds its transient limit is calculated based on the following expressions:

$$\left\{ \underset{\text{over } Z}{\text{maximum}} \left[\frac{F_Q\,(Z)\,W\,(Z)}{\frac{F_Q^{RTP}\,K\,(Z)}{P}} \right] - 1 \right\} \text{ x } 100 \text{ for } P > 0.5$$

(continued)

ACTIONS

B.1 (continued)

$$\left\{ \underset{\text{over } Z}{\text{maximum}} \left[\frac{F_Q\,(Z)\,W\,(Z)}{\dfrac{F_Q^{RTP}\;K\,(Z)}{0.5}} \right] - 1 \right\} \text{ x } 100 \text{ for } P \le 0.5$$

C.1

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

This 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.

SURVEILLANCE REQUIREMENTS

During power ascension following a refueling, the first determination of $F_Q(Z)$ is not required until after achieving equilibrium conditions at any power level above 50% RTP. This Frequency condition, together with the Frequency condition requiring verification of $F_Q(Z)$ and following a power increase of more than 20%, 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 $F_Q(Z)$. The Frequency condition is not intended to require verification of these parameters after every 20% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is at least 20% higher than that power at which $F_Q(Z)$ was last measured.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.1

This surveillance determines if $F_Q(Z)$will remain within its limit during steady-state operations.

TRM TR 13.3.1 specifies the movable incore detector system FUNCTIONAL requirements if a flux map is used for performing this surveillance.

Performing this Surveillance in MODE 1 after exceeding 50% RTP following refueling ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased. In addition, at power levels above 50% RTP, equilibrium Xenon conditions approach those more closely at RTP. Therefore, performing the Surveillance at a power level above 50% RTP ensures a more accurate measurement of $F_Q(Z)$.

If THERMAL POWER has been increased by ≥ 20% RTP since the last determination of $F_Q(Z)$, another evaluation of this factor is required after achieving equilibrium conditions at this higher power level (to ensure that $F_Q(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

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

SR 3.2.1.2

This surveillance determines if $F_Q(Z)$ will remain within its limit during a normal operational transient. If $F_Q(Z)$ is determined to exceed the transient limit, Action B.1 requires that the AFD limit be reduced 1% for each 1% $F_Q(Z)$ exceeds the transient limit. This

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

will ensure that $F_Q(Z)$ will not exceed the transient limit during a normal operational transient within the reduced AFD limit.

Demonstrating that $F_Q(Z)$ is within the transient limit or reducing the AFD limit if the transient $F_Q(Z)$ limit was initially exceeded, only ensures that the transient $F_Q(Z)$ limit will not be exceeded at the time $F_Q(Z)$ was evaluated. This does not ensure that the limit will not be exceeded during the following surveillance interval. Both the steady state and transient $F_Q(Z)$ change as a function of core burnup.

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

$$\text{maximum over z} \left[\frac{F_Q(Z)}{k(Z)}\right],$$

it is not guaranteed that $F_Q(Z)$ will remain within the transient limit during the following surveillance interval. SR 3.2.1.2 is modified by a Note to determine if there is sufficient margin to the transient $F_Q(Z)$ limit to ensure that the limit will not be exceeded during the following surveillance interval. This is accomplished by increasing $F_Q(Z)$ by a penalty specified in the COLR and comparing this value to the transient $F_Q(Z)$ limit. If there is insufficient margin, i.e., this value exceeds the limit, SR 3.2.1.2 must be repeated once per 7 EFPD until either $F_Q(Z)$ increased by the penalty factor is within the transient limit or, two successive (i.e., subsequent consecutive) surveillances indicate

$$\text{maximum over z} \left[\frac{F_Q(Z)}{k(Z)}\right],$$

has not increased.

Performing the Surveillance in MODE 1 after exceeding 50% RTP following refueling ensures that the $F_Q(Z)$ limits are met when RTP is achieved, because peaking factors are generally decreased as power level is increased. In addition, at power levels above 50% RTP, equilibrium Xenon conditions approach more closely those at RTP. Therefore, performing the Surveillance at a power level above 50% RTP ensures a more accurate measurement of $F_Q(Z)$.

$F_Q(Z)$ is verified at power levels ≥ 20% RTP above the THERMAL POWER of its last verification, after achieving

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

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.

REFERENCES

1. 10 CFR 50.46, 1974.
2. FSAR Subsection 15.4.8.
3. 10 CFR 50, Appendix A, GDC 26.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
5. WCAP-10216-P-A, Revision 1A, "Relaxation of Constant Axial Offset Control FQ Surveillance Technical Specification," February 1994.
6. GP-18735, “Evaluation of a Reduction in the Required Number of Movable Incore Detector Thimbles,” January 31, 2011.
7. GP-18767, “Southern Nuclear Operating Company, Vogtle Electric Generating Plant Units 1 and 2, Cycle 17 Movable Incore Detector Thimble Evaluation,” April 4, 2011.
8. WCAP-12472-P-A “BEACON Core Monitoring and Operations Support System,” August 1994.

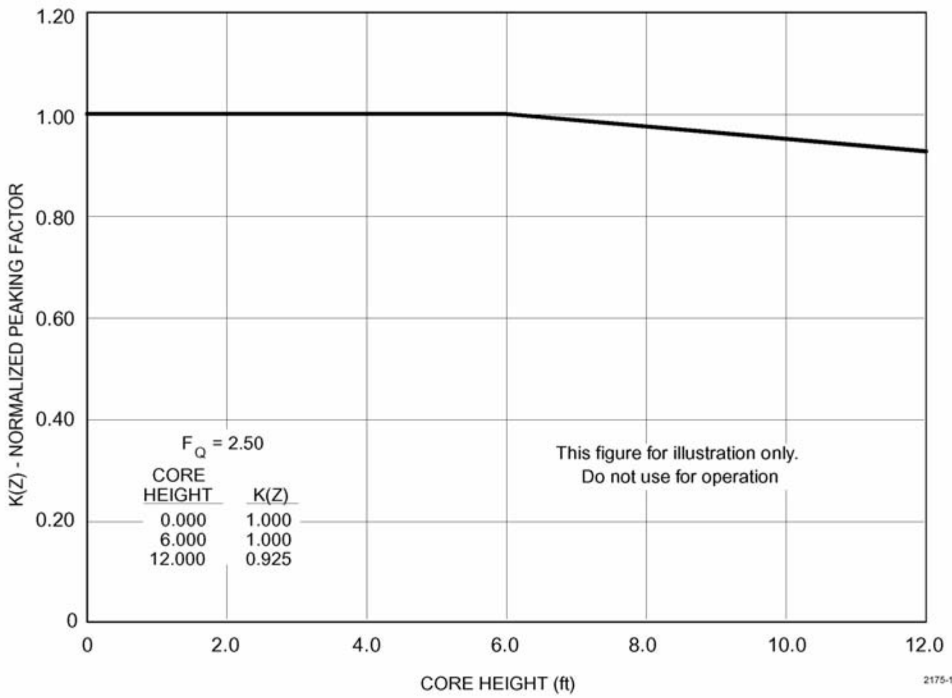


Figure B 3.2.1-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ As A Function of Core Height

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 fuel design limits 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, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from core power distribution information. Specifically, the results of the three dimensional power distribution information are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, 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.

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.

(continued)

BASES

BACKGROUND (continued)

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 large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F;

c. During an ejected rod accident, the fission energy input to the fuel will be below 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 SDM 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 DNBR limits.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.7, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using core power distribution information. 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 Bank Insertion Limits.

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

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 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 unit safety analyses.

(continued)

BASES

LCO (continued)

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

APPLICABILITY

The $F_{\Delta H}^{N}$ limits must be maintained in MODE 1 to preclude 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 coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F_{\Delta H}^{N}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F_{\Delta H}^{N}$ in these modes.

ACTIONS

A.1.1

With $F_{\Delta H}^{N}$ exceeding its limit, the unit is allowed 4 hours to restore $F_{\Delta H}^{N}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F_{\Delta H}^{N}$ within its power dependent limit. When the $F_{\Delta H}^{N}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F_{\Delta H}^{N}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F_{\Delta H}^{N}$ to within its limits without allowing the plant 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.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because $F_{\Delta H}^{N}$ is restored to within the limit within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F_{\Delta H}^{N}$ within 24 hours in accordance with SR 3.2.2.1.

(continued)

BASES

ACTIONS

A.1.1 (continued)

However, if power is reduced below 50% RTP, Required Action A.3 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. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

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, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux — High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 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.

A.2

Once corrective action has been taken in accordance with Required Action A.1.1 or A.1.2.1, (SR 3.2.2.1) must be performed and the measured value of $F^N_{\Delta H}$

(continued)

BASES

ACTIONS

A.2 (continued)

verified not to exceed the allowed limit. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the low probability of having a DNB limiting event within this 24 hour period, and, in the event that power was reduced, the increase in DNB margin which is obtained at lower power levels. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain core power distribution information, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence 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 $\geq$ 95% RTP.

This Required Action is modified by a Note that clarifies that it is only applicable to the extent that THERMAL POWER has been reduced to comply with Required Actions A.1.1 or A.1.2.1. For example, if THERMAL POWER was reduced to less than 50%, SR 3.2.2.1 must be performed prior to THERMAL POWER exceeding 50%, 75%, and within 24 hours after reaching 95% RTP. If however, THERMAL POWER was only reduced to 70% RTP, then SR 3.2.2.1 must be performed prior to exceeding 75% RTP and within 24 hours after reaching 95% RTP. This course of action will provide assurance that $F^N_{\Delta H}$ has been restored to limits.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least

(continued)

BASES

ACTIONS

B.1 (continued)

MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by obtaining core power distribution information. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the core power distributions. Before making comparisons to the $F^N_{\Delta H}$ limit, the measured value of $F^N_{\Delta H}$ must be multiplied by a measurement uncertainty factor. If the core power distribution information is obtained with the Power Distribution Monitoring System (PDMS), the measured value of FNDH must be multiplied by the factor [1.0 + ($U_{\Delta H}$ /100)] where $U_{\Delta H}$ accounts for PDMS uncertainty determined as described in Equation 5-19 of Ref. 4. If the power distribution is obtained from a flux map using the movable incore system with ≥ 44 detector thimbles, the measured value of $F^N_{\Delta H}$ must be multiplied by 1.04. When using ≥ 29 and < 44 detector thimbles, the measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 + [2.0 {3-T/(14.5)}]/100, where T = the number of detector thimbles used. A bounding measurement uncertainty of 6.0 %, which is based on 29 thimbles, can be used for ≥ 29 and < 44 detector thimbles, if desired. During the initial startup after a refueling outage up to and including performance of the first flux map at 100% RTP, ≥ 44 detector thimbles, with ≥ 2 detector thimbles per core quadrant as identified in TRM Figure 13.3.1-1 are required. This Note does not have to be met for Vogtle Unit 1, Cycle 17 based on the successful performance of the flux map at 30% RTP.

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

(continued)

BASES

REFERENCES

1. FSAR Subsection 15.4.8.
2. 10 CFR 50, Appendix A, GDC 26.
3. 10 CFR 50.46.
4. WCAP-12472-P-A “BEACON Core Monitoring and Operations Support System,” August 1994

(continued)

BASES (continued)

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 (Ref. 2) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional 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 satisfy Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is under the control of the operator through the manual operation of the control banks.

(continued)

BASES

LCO
(continued)

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (NI-0041B, NI-0042B, NI-0043B, NI-0044B). 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 multiplied by nuclear gain such that AFD equals core average axial offset at Rated Thermal Power.

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RAOC AFD limits. 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 above 50% RTP 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.

ACTIONS

A.1

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

(continued)

BASES

ACTIONS

A.1 (continued)

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

SR 3.2.3.1

This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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-10216(NP), June 1983.

BASES

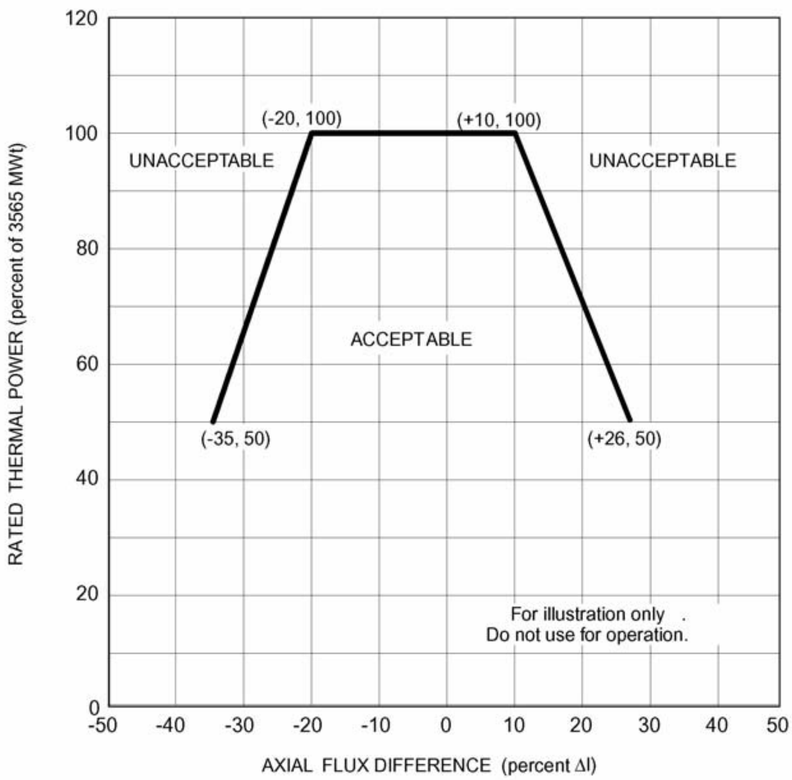


FIGURE B 3.2.3-1
AXIAL FLUX DIFFERENCE LIMITS AS A FUNCTION OF RATED THERMAL POWER FOR RAOC

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the radial power distribution remains consistent with the design values used in the safety analyses. The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.7, "Control Rod Insertion Limits," 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.

APPLICABLE SAFETY ANALYSES

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

a. During a large break loss of coolant accident, the peak cladding temperature must 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 fission energy input to the fuel will be below 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).

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 are

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 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 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. The value of 1.02 was selected because the purpose of the LCO is to limit, or require detection of, gross changes in core power distribution between monthly determination of core power distribution information. In addition, it is the lowest value of quadrant power tilt that can be used for an alarm without spurious actuation.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP 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 either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

(continued)

BASES (continued)

ACTIONS

A.1

With the QPTR exceeding its limit, limiting THERMAL POWER to $\geq$ 3% below 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.

A.2.1 and A.2.2

Because the QPTR alarm is already in its alarmed state, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours. If the QPTR continues to increase, THERMAL POWER has to be reduced accordingly within the following 2 hours. A Note clarifies that the Completion Time of Required Action A.2.2 begins after Required Action A.2.1 is complete. These Completion Times are sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, 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 FQ(Z) within the Completion Time of 24 hours after achieving equilibrium conditions with THERMAL POWER limited by Required Action A.1 or A.2.2 ensures that these primary indicators of power distribution are within their respective limits. The above Completion Time takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and obtain core power distribution information. 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

(continued)

BASES

ACTIONS

A.3 (continued)

$F_Q(Z)$ 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

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 radial power distribution that requires an investigation and evaluation that is accomplished by examining the core power distribution. Specifically, the core peaking must be evaluated because they are the factors that best characterize the core power distribution. This reevaluation is required to ensure that, for the duration of operation in accordance with Condition A of this LCO, before increasing THERMAL POWER to above the limit of Required Action A.1 and A.2.2, the reactor core conditions (peaking factors) are consistent with the assumptions in the safety analyses and will remain so after the return to RTP.

However, if prior to performing SR 3.2.1.1 and SR 3.2.2.1, QPTR is restored to within the limit, either due to prior completion of Required Actions or due to core performance characteristics that result in the QPTR out-of-limit condition correcting itself, Required Action A.3 and any other required actions would no longer apply because Condition A of LCO 3.2.4 would be exited in accordance with LCO 3.0.2 due to restoration of full compliance with LCO 3.2.4.

If it is determined that a sustained change in the radial power distribution has occurred, and Required Action A.3 has been completed with satisfactory results, an increase in THERMAL POWER above the limit of Required Action A.1 may be appropriate. The necessary sequence of Required Actions, beginning with Required Action A.4, would be as follows prior to increasing THERMAL POWER above the limit of Required Action A.1 and A.2.2.

(continued)

BASES

ACTIONS

A.4 (continued)

1. Verify by the reevaluation of the safety analyses that after the sustained change in radial power distribution, the core conditions remain within the assumptions of the safety analyses and will remain so after return to RTP (Required Action A.4), and

2. Recalibrate the power range detectors to reset QPTR to 1.00 (Required Action A.5).

If these actions are completed with satisfactory results, THERMAL POWER may be increased above the limit of Required Action A.1 and A.2.2. After power is increased, the peaking factors are again verified to be within limits. Upon the satisfactory completion of Required Action A.6, Condition A of LCO 3.2.4 can be exited.

A.5

If the QPTR has exceeded the 1.02 limit and a reevaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are recalibrated to show a QPTR of 1.00 prior to increasing THERMAL POWER to above the limit of Required Action A.1 and A.2.2. This is done to detect subsequent changes in QPTR. For tilted conditions caused by power reduction, allowing time to pass may permit QPTR to return to ≤ 1.02, thus avoiding the need to recalibrate the power range detectors.

Required Action A.5 is modified by a Note that states that the QPTR is not recalibrated to 1.00 until after the reevaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). This Note is intended to prevent any ambiguity about the required sequence of actions.

A.6

Once QPTR is recalibrated to 1.00 (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

(continued)

BASES

ACTIONS

A.6 (continued)

power distribution at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$, as approximated by the steady state and transient $F_Q(Z)$, and $F^N_{\Delta H}$ are within their specified limits within 24 hours of reaching 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 of the time when the ascent to power was begun. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1 and A.2.2, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

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 calibrated to show QPTR = 1.00 (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 calibrated to show QPTR = 1.00 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

SR 3.2.4.1 is modified by a Note that allows QPTR to be calculated with three power range channels if one power range channel is inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1 (continued)

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. Valid inputs to the detector current comparator from the upper and lower sections from 3 or 4 power range channels are required for the QPTR alarm to be OPERABLE.

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

SR 3.2.4.2

This Surveillance is modified by a Note, which states that the surveillance is only required to be performed if input to QPTR from one or more Power Range Neutron Flux channels is inoperable with THERMAL POWER $\geq$75% RTP.

With 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.

When one power range channel is inoperable either the Power Distribution Monitoring System (PDMS) or the movable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR. 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. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, and N-8.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

The flux map or the Power Distribution Monitoring System (PDMS) can be used to generate power tilt. This can be compared to a reference tilt, from the most recent calibration flux map. Therefore, the incore detectors can be used to confirm the accuracy of the QPTR as indicated by the excore detectors.

REFERENCES

1. 10 CFR 50.46.

2. FSAR Subsection 15.4.8.

3. 10 CFR 50, Appendix A, GDC 26.

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, 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 2750 psia shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 20 and 10 CFR 100 criteria during AOOs.

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 offsite dose shall be maintained within an acceptable fraction of 10 CFR 100

(continued)

BACKGROUND (continued)

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 illustrated in Figure 7.1.1-1, FSAR, Chapter 7 (Ref. 1), and as identified below:

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: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system channels, 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.

<u>Field Transmitters or Sensors</u>

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

(continued)

BACKGROUND

Field Transmitters or Sensors (continued)

are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint (NTSP) 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 NTSPs derived from Analytical Limits established by the safety analyses. Analytical Limits are defined in FSAR, Chapter 7 (Ref. 1), Chapter 6 (Ref. 2), and Chapter 15 (Ref. 3). 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 unit 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.

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

(continued)

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

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 logic channels 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 trip. Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.

Nominal Trip Setpoints and Allowable Values

The trip setpoints used in the bistables are based on the analytical limits stated in Reference 1. The calculation of the Nominal Trip Setpoints specified in Table 3.3.1-1 is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Values and NTSPs, including their explicit uncertainties, is provided in the "RTS/ESFAS Setpoint Methodology Study" (Ref. 6). The as-left and as-found tolerance band methodology is provided in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions. The magnitudes of these uncertainties are factored into the determination of each NTSP and corresponding Allowable Value. The trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. The Allowable Value serves as the as-found Technical Specification OPERABILITY limit for the purpose of the COT.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Nominal Trip Setpoints in conjunction with the use of as-found and as-left tolerances, together with the requirements of the Allowable Value 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 AOO or DBA and the equipment functions as designed). For the purpose of demonstrating compliance with 10 CFR 50.36 to the extent that the Technical Specifications are required to specify Limiting Safety System Settings (LSSS), the LSSS for VEGP are comprised of the Nominal Trip Setpoints specified in Table 3.3.1-1. The Nominal Trip Setpoint is the expected value to be achieved during calibrations. The Nominal Trip Setpoint considers all factors which may affect channel performance by statistically combining rack drift, rack measurement and test equipment effects, rack calibration accuracy, rack comparator setting accuracy, rack temperature effects, sensor measurement and test equipment effects, sensor calibration accuracy, primary element accuracy, and process measurement accuracy. The Nominal Trip Setpoint is the value that will always ensure that safety analysis limits are met (with margin) given all of the above effects. The Allowable Value has been established by considering the values assumed for rack effects only. Note that the Allowable Values listed in Table 3.3.1-1 are the least conservative value of the as-found setpoint that a channel can have during a periodic CHANNEL CALIBRATION, CHANNEL OPERATIONAL TESTS, or a TRIP ACTUATING DEVICE OPERATIONAL TEST that requires a trip setpoint verification.

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Nominal Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 6, which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal

(continued)

BACKGROUND

Trip Setpoints and Allowable Values (continued)

processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

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

(continued)

BASES

BACKGROUND

Solid State Protection System (continued)

requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

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 unit upset and accident 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 from the SSPS. Either the undervoltage coil or the shunt

(continued)

BASES

BACKGROUND

Reactor Trip Switchgear (continued)

trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

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 channels 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 preserve the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in LCO, and which the RTBs are closed.

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 that are retained yet not specifically credited in the accident analysis are implicitly 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.

Permissive and interlock setpoints allow the blocking of trips during plant startups and restoration of trips when the permissive conditions are not satisfied, but they are not explicitly modeled in the Safety Analyses. These permissives and interlocks ensure that the starting conditions are consistent with the safety analysis before preventative or mitigating actions occur. Because these permissives or interlocks are only one of multiple conservative starting assumptions for the accident analysis, they are generally considered as nominal values without regard to measurement accuracy.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 to be OPERABLE. The Allowable Value specified in Table 3.3.1-1 is the least conservative value of the as-found setpoint that the channel can have when tested, such that a

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

channel is OPERABLE if the as-found setpoint is within the as-found tolerance and is conservative with respect to the Allowable Value during a CHANNEL CALIBRATION or CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the NTSP by an amount greater than or equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the channel (NTSP) will ensure that a SL is not exceeded at any given point of time as long as the channel has not drifted beyond expected tolerances during the surveillance interval. Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the as-left tolerance, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned (as-found criteria).

If the actual setting of the channel is found to be conservative with respect to the Allowable Value but is beyond the as-found tolerance band, the channel is OPERABLE but degraded. The degraded condition of the channel will be further evaluated during performance of the SR. This evaluation will consist of resetting the channel setpoint to the NTSP (within the allowed tolerance), and evaluating the channel response. If the channel is functioning as required and is expected to pass the next surveillance, then the channel is OPERABLE and can be restored to service at the completion of the surveillance. After the surveillance is completed, the channel as-found condition will be entered into the Corrective Action Program for further evaluation.

A trip setpoint may be set more conservative than the NTSP as necessary in response to plant conditions. However, in this case, the operability of this instrument must be verified based on the field setting and not the NTSP. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The conservative direction is established by the direction of the inequality applied to the Allowable Value. It is consistent with the setpoint methodology for the as-left trip setpoint to be outside the calibration tolerance but in the conservative direction with respect to the Nominal Trip Setpoint. For example, the Power Range Neutron Flux High trip setpoint may be set to a value less than 109% during initial startup following a refueling outage until a

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

sufficiently high reactor power is achieved so that the power range channels may be calibrated. In addition, certain Required Actions may require that the Power Range Neutron Flux High trip setpoints and/or the Overpower Delta-T setpoints be reduced based on plant conditions.

The LCO generally requires OPERABILITY of four or three 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. If an instrument channel is equipped with installed bypass capability, such that no jumpers or lifted leads are required to place the channel in bypass and annunciation of the bypass condition is available in the control room, corrective maintenance and testing of that channel may be performed in the bypass condition. Bypassing a channel renders that channel inoperable and the associated Required Actions for that channel are applicable. 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel actuates 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 the shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the 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. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor because all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors (NI-0041B & C, NI-0042B & C, NI-0043B & C, NI-0044B & C) 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. 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.

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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.

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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Power Range Neutron Flux — Low (continued)

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 reactivity excursions such as an inadvertent control rod withdrawal or 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.

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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Power Range Neutron Flux — High Positive Rate (continued)

OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this mode.

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux (NI-035B, D, & E, NI-036B, D, & G) 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. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip.

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.

In MODE 1 below the P-10 setpoint, and in MODE 2, 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Intermediate Range Neutron Flux (continued)

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 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because 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 indication is typically low off-scale in this MODE.

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip (NI-0031B, D, & E, NI-0032B, D, & G) 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 and Intermediate Range Neutron Flux trip Functions. 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. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The LCO also requires two channels of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs closed.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Source Range Neutron Flux (continued)

subcritical, boron dilution (see LCO 3.3.8) and control rod ejection events. The Function also provides visual neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux — Low Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the Source Range Neutron Flux trip is blocked.

In MODE 3, 4, or 5 with the reactor shut down, the Source Range Neutron Flux trip Function must also be OPERABLE. If the Rod Control System is capable of rod withdrawal, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal accident. If the Rod Control System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. Source range detectors also function to monitor for high flux at shutdown. This function is addressed in Specification 3.3.8. Requirements for the source range detectors in MODE 6 are addressed in LCO 3.9.3.

6. Overtemperature ΔT

The Overtemperature ΔT trip Function (TDI-0411C, TDI-0421C, TDI-0431C, TDI-0441C, TDI-0411A, TDI-0421A, TDI-0431A, TDI-0441A) 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 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

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

has the same 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 — f(AFD)x, the f(AFD) Function is used in the calculation of the Overtemperature ΔT trip. It is a function of the indicated difference between the upper and lower NIS power range detectors. This Function measures the 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 RTD response time delays.

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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overtemperature ΔT (continued)

This results in a two-out-of-four trip logic. Section 7.2.2.3 of Reference 1 discusses control and protection system interactions for this function. 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.

Delta-T_0, as used in the overtemperature and overpower ΔT trips, represents the 100% RTP value as measured for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., differences in RCS loop flows and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Therefore, loop specific ΔT_0 values are measured as needed to ensure they represent actual core conditions.

The parameter K_1 is the principal setpoint gain, since it defines the function offset. The parameters K_2 and K_3 define the temperature gain and pressure gain, respectively. The values for T' and P' are key reference parameters corresponding directly to plant safety analyses initial conditions assumptions for the Overtemperature ΔT function. For the purposes of performing a CHANNEL CALIBRATION, the values for K_1, K_2, K_3, T', and P' are utilized in the safety analyses without explicit tolerances, but should be considered as nominal values for instrument settings. That is, while an exact setting is not expected, a setting as close as reasonably possible is desired. Note that for T', the value for the hottest RCS loop will be set

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLITY

6. Overtemperature ΔT (continued)

as close as possible to 588.4° F. The instrument uncertainty calculations and safety analyses, in combination, have accounted for loop variation in loop specific, full power, indicated ΔT and $T_{avg.}$ With respect to T_{avg}, a value for T' common to all four loops is permissible within the limits identified in the uncertainty calculations. Outside of those limits, the value of T' will be set appropriately to reflect indicated, loop specific, full power values. In the case of decreasing temperature, the compensated temperature difference shall be no more negative than 3 °F to limit the increase in the setpoint during cooldown transients. The engineering scaling calculations use each of the referenced parameters as an exact gain or reference value. Tolerances are not applied to the individual gain or reference parameters. Tolerances are applied to each calibration module and the overall string calibration. In order to ensure that the Overtemperature ΔT instrument channel is performing in a manner consistent with the assumptions of the safety analyses, it is necessary to verify during the CHANNEL OPERATIONAL TEST that the magnitude of instrument drift from the as-left condition is within limits, and that the input parameters to the trip function are within the appropriate calibration tolerances for the defined calibration conditions (Ref. 7).

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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT

The Overpower ΔT trip Function (TDI-0411B, TDI-0421B, TDI-0431B, TDI-0441B, TDI-0411A, TDI-0421A, TDI-0431A, TDI-0441A) 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 Setpoint 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 RTD response time delays.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. 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. This results in a two-out-of-four trip logic. Section 7.2.2.3 of Reference 1 discusses control and protection system interactions for this function. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

Delta-T_0, as used in the overtemperature and overpower ΔT trips, represents the 100% RTP value as measured for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., difference in RCS loop flows and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Therefore, loop specific ΔT_0 values are measured as needed to ensure they represent actual core conditions.

The value for T" is a key reference parameter corresponding directly to plant safety analyses initial conditions assumptions for the Overpower ΔT function. For the purposes of performing a CHANNEL CALIBRATION, the values for K_4, K_5, K_6, and T" are utilized in the safety analyses without explicit tolerances, but should be considered as nominal values for instrument settings. That is, while an exact setting is not expected, a setting as close as reasonably possible is desired. Note that for T", the value for the hottest RCS loop will be set as close as possible to 588.4° F. The instrument uncertainty calculations and safety analyses, in combination, have accounted for loop variation in loop specific, full power, indicated ΔT and T_{avg}. With respect to T_{avg}, a value for T" common to all four loops is permissible within the limits identified in the uncertainty calculations. Outside of those limits, the value of T" will be set appropriately to reflect indicated, loop specific, full power values. The engineering scaling calculations use each of the referenced parameters as an exact gain or reference value. Tolerances are not applied to the individual gain or reference parameters. Tolerances are applied to each calibration module and the overall string calibration. In order to ensure that the Overpower ΔT instrument channel is performing in a manner consistent with the assumptions of the safety analyses, it is necessary to verify during the CHANNEL OPERATIONAL TEST that the magnitude of instrument drift from the as-left condition is within limits, and that the input parameters to the trip function are within the appropriate calibration tolerances for defined calibration conditions (Ref. 7). Note that for the parameter K_5, in the case of

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Overpower ΔT (continued)

decreasing temperature, the gain setting must be ≥ 0 to prevent generating setpoint margin on decreasing temperature rates. Similarly, the setting for K_6 is required to be equal to 0 for conditions where T ≤ T".

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. Pressurizer Pressure

The same sensors (PI-0455A, B, & C, PI-0456, PI-0456A, PI-0457, PI-0457A, PI-0458, PI-0458A) 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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Pressurizer Pressure (continued)

the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Section 7.2.2.3 of Reference 1 discusses control and protection system interactions for this function.

a. Pressurizer Pressure — Low

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.

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 greater than approximately 10% of full power equivalent (P-13)). 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Pressurizer Pressure — High (continued)

minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

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. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

9. Pressurizer Water Level — High

(LI-0459A, LI-460A, LI-0461A)

NOTE: Pressurizer Water Level channels are also required OPERABLE by the Post Accident Monitoring Technical Specification. Setpoints are given in percent of instrument span.

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 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Pressurizer Water Level — High (continued)

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.

In MODE 1, when there is a potential for over filling 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

(LOOP 1	LOOP 2	LOOP 3	LOOP 4
FI-0414	FI-0424	FI-0434	FI-0444
FI-0415	FI-0425	FI-0435	FI-0445
FI-0416	FI-0426	FI-0436	FI-0446)

NOTE: The setpoints are given in percent of Loop flow.

a. Reactor Coolant Flow — Low (Single Loop)

The Reactor Coolant Flow — Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, which is approximately 48% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Reactor Coolant Flow — Low (Single Loop) (continued)

The LCO requires three Reactor Coolant Flow — Low channels per loop to be OPERABLE in MODE 1 above P-8.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function 10.b) because of the lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Flow — Low (Two Loops)

The Reactor Coolant Flow — Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

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. Each 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 the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow — Low (Two Loops) trip must be OPERABLE. 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. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Reactor Coolant Flow — Low (Two Loops) (continued)

power level and the reduced margin to the design limit DNBR.

11. 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 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.

Two undervoltage relays (train A and B) sense the voltage on the motorside of each RCP breaker. Actuation of either relay provides a single channel input for that pump (bus) to the 2/4 reactor trip logic consisting of a combination of RCP No. 1 or RCP No. 2 and RCP No. 3 or RCP No. 4.

The Trip Setpoint is equal to 70% of bus voltage and the Allowable Value is equal to 69% of bus voltage.

The LCO requires two Undervoltage RCPs channels per bus to be OPERABLE (one per RCP).

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 low voltage in two or more RCS loops is automatically enabled.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

12. 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 RCP buses will initiate a reactor trip and open the reactor coolant pump breakers. 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.

Two underfrequency relays (train A and B) sense the frequency on the motorside of each RCP breaker. Actuation of either relay provides a single channel input for that pump (bus) to the 2/4 reactor trip logic consisting of a combination of RCP No. 1 or RCP No. 2 and RCP No. 3 or RCP No. 4.

The LCO requires two Underfrequency RCPs channels per bus to be OPERABLE (one per RCP).

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 underfrequency in two or more RCS loops is automatically enabled.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Steam Generator Water Level — Low Low

(LOOP1	LOOP2	LOOP3	LOOP4
LI-0517	LI-0527	LI-0537	LI-0547
LI-0518	LI-0528	LI-0538	LI-0548
LI-0519	LI-0529	LI-0539	LI-0549
LI-0551	LI-0552	LI-0553	LI-0554)

NOTE: SG Water Level channels are also required OPERABLE by the Post Accident Monitoring Technical Specification. The setpoints are given in percent of narrow range instrument span.

The SG Water Level — Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW 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 AFW pumps on low low SG level.

The LCO requires four channels of SG Water Level — Low Low per SG to be OPERABLE for four loop units in which these channels are shared between protection and control.

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 Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW 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 AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level — Low Low

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

13. Steam Generator Water Level — Low Low (continued)

Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not operating or even critical. Decay heat removal is accomplished by the AFW System in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. Turbine Trip

(PT-6161, PT-6162, PT-6163)

a. Turbine Trip — Low Fluid Oil Pressure

The Turbine Trip — Low Fluid Oil 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-9 setpoint, approximately 40% power, will not actuate a reactor trip. 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 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 of Turbine Trip — Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-9.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Turbine Trip — Low Fluid Oil Pressure (continued)

Below the P-9 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 — Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip — Turbine Stop Valve Closure

The Turbine Trip — Turbine Stop 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-9 setpoint, approximately 40% power. Below the P-9 setpoint this action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop 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 — Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If all four limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

The Nominal Trip Setpoint for this Function is set to assure channel trip occurs when the associated stop valve is not fully open (approximately 3.3% closed).

Since the stop valves are designed to fully close once tripped, any indication that the valve is no longer fully open is sufficient to determine the trip status. Because the stop valves close so quickly, any indication near the fully open position (such as 90% open) provides sufficient assurance that the stop valve is going closed. Therefore, for this function, the allowable value was established as an operability limit for the channel operational test.

The LCO requires four Turbine Trip — Turbine Stop Valve Closure channels, one per valve, to be

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Turbine Trip — Turbine Stop Valve Closure (continued)

OPERABLE in MODE 1 above P-9. All four channels must trip to cause reactor trip.

Below the P-9 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 — Stop Valve Closure trip Function does not need to be OPERABLE.

15. Safety Injection 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. Reactor trip is not credited in the large break LOCA analysis. 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.

Trip Setpoint and 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 channels 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

16. 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. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock (NI-0035B, D, & E, NI-0036B, D, & G) 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.

- on decreasing power, the P-6 interlock automatically enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 (continued)

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.

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);
- Undervoltage RCPs; and
- Underfrequency RCPs.

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:

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 (continued)

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

Trip Setpoint and 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 P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

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 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock (NI-0041B & C, NI-0042B & C, NI-0043B & C, NI-0044B & C) is actuated at approximately 48% 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Power Range Neutron Flux, P-8 (continued)

when greater than approximately 48% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four 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.

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock (NI-0041B & C, NI-0042B & C, NI-0043B & C, NI-0044B & C) is actuated at approximately 40% power as determined by two-out-of-four NIS power range detectors. The LCO requirement for this Function ensures that the Turbine Trip — Low Fluid Oil Pressure and Turbine Trip — Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will 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-9 setpoint, to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-9 (continued)

reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock (NI-0041B & C, NI-0042B & C, NI-0043B & C, NI-0044B & C) 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

- 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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Power Range Neutron Flux, P-10 (continued)

The LCO requires four 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.

f. Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 interlock (PI-0505, PI-0506) is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full load pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

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 reactor trips enabled by P-7 are not required.

17. 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

17. Reactor Trip Breakers (continued)

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. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. 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 RTBs or associated bypass breakers are closed, and the Rod Control System is capable of rod withdrawal.

18. 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 17 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 RTBs and associated bypass breakers are closed, and the Rod Control System is capable of rod withdrawal.

19. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 17 and 18) and Automatic Trip Logic (Function 19) 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

19. Automatic Trip Logic (continued)

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 channels of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel 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 RTBs or associated bypass breakers are closed, and the Rod Control System is capable of rod withdrawal.

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 NTSB is found nonconservative with respect to the Allowable Value, or the channel is not functioning as required, 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 number of inoperable channels in a trip Function exceed those specified in one or other 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.

(continued)

ACTIONS (continued)

A.1

Condition A applies to all RTS protection functions. Condition A addresses the situation where one or more required channels 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 and B.2

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. 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 channels and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which Condition B is no longer applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, Condition C applies to this trip function.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal:

(continued)

ACTIONS

C.1 and C.2 (continued)

- 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 RTBs must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, these Functions are no longer required. This Condition is modified by a Note that prohibits closing the RTBs in MODES 3, 4, or 5 if any of the above Functions (Function 1, 17, 18, or 19 of Table 3.3.1-1) are not met.

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

D.1 and D.2

Condition D applies to the Power Range Neutron Flux — High Function. This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

The NIS power range detectors provide input to the CRD 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 WCAP-14333-P-A (Ref. 8).

The Required Actions have been modified by two Notes. Note 1 allows a channel to be placed in the bypassed condition for up to 12 hours while performing routine surveillance testing. With one channel inoperable, the Note also allows routine surveillance testing of another channel with a channel in bypass. The Note also allows placing a channel in the bypass condition to allow setpoint adjustments when required to reduce the Power Range Neutron Flux-High setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 8.

Note 2 refers the user to LOC 3.2.4 for additional requirements that may apply for an inoperable power range channel.

If Required Action D.1 cannot be met within the specified Completion Time, the unit must be placed in a MODE where this Function is no longer required OPERABLE. An additional 6 hours beyond the Completion Time for Required Action D.1 is allowed to place the unit in MODE 3. Six 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.

(continued)

ACTIONS (continued)

E.1 and E.2

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.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

(continued)

ACTIONS

E.1 and E.2 (continued)

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and 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 8.

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing a channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. With one channel inoperable, the Note also allows routine surveillance testing of another channel with a channel in bypass. The 12 hour time limit is justified in Reference 8.

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, 24 hours are allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be 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

(continued)

ACTIONS

F.1 and F.2 (continued)

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 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. However, this does not preclude actions to maintain or increase reactor vessel inventory or place the unit in a safe conservative condition provided the required SDM is maintained. The suspension of positive reactivity additions 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 the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels are inoperable. Below the P-6 setpoint, the NIS source range performs the monitoring and protection functions. The inoperable NIS intermediate range channel(s) must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. The NIS intermediate range channels must be 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.

(continued)

ACTIONS (continued)

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. 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.

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. However, this does not preclude actions to maintain or place the unit in a safe conservative condition provided the required SDM is maintained.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and performing a reactor startup, or in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. 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 and the unit enters Condition L.

K.1 and K.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. 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, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit enters Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 9.

(continued)

BASES

ACTIONS (continued)

L.1

Condition L applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. However, this does not preclude actions to maintain or increase reactor vessel inventory or place the unit in a safe conservative condition provided the required SDM is maintained. Note that the source range also continues to provide input to the high flux at shutdown alarm (HFASA - LCO 3.3.8). LCO 3.3.8 requires that the HFASA receive input from two source range channels for the HFASA to be OPERABLE.

M.1 and M.2

Condition M applies to the following reactor trip Functions:

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

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. 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 (and below the P-8 setpoint for the Reactor Coolant Flow — Low — Two Loops

(continued)

ACTIONS

M.1 and M.2 (continued)

function). These Functions do not have to be OPERABLE below the P-7 setpoint because for the Pressurizer Water Level — High transients are slow enough for manual action, and for the other functions DNB is not as serious a concern due to the Low Power Level. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 8. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

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 M.

The Required Actions have been modified by two Notes. Note 1 applies only to the RCP undervoltage and underfrequency instrument functions. These functions do not have installed bypass capability. Therefore, the allowance to place these instrument channels in bypass is more limited. Note 1 allows the inoperable undervoltage or underfrequency instrument channel to be bypassed for up to 12 hours for surveillance testing of other channels.

Note 2 allows placing a channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. Note 2 applies to all Condition M instrument functions except RCP undervoltage and underfrequency. With one channel inoperable, Note 2 also allows routine surveillance testing of another channel with a channel in bypass. The 12 hour time limit of both Notes is justified in Reference 8.

N.1 and N.2

Condition N applies to the Reactor Coolant Flow — Low (Single Loop) reactor trip Function. This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from

(continued)

ACTIONS

N.1 and N.2 (continued)

applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition. With one channel inoperable, the inoperable channel must be placed in trip within 72 hours. If the channel cannot be restored to OPERABLE status or the channel placed in trip within the 72 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours. This places the unit in a MODE where the LCO is no longer applicable. This trip Function does not have to be OPERABLE below the P-8 setpoint because other RTS trip Functions provide core protection below the P-8 setpoint. The 72 hours allowed to restore the channel to OPERABLE status or place in trip and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 8.

The Required Actions have been modified by a Note that allows placing a channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. With one channel inoperable, the Note allows routine surveillance testing of another channel with a channel in bypass. The 12 hour time limit is justified in Reference 8.

O.1 and O.2

Condition O applies to Turbine Trip on Low Fluid Oil Pressure. This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition. With one channel inoperable, the inoperable channel must be placed in the trip

(continued)

ACTIONS

O.1 and O.2 (continued)

condition within 72 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 8.

The Required Actions have been modified by a Note that allows placing a channel in the bypassed condition for up to 12 hours while performing routine surveillance testing. With one channel inoperable, the Note also allows routine surveillance testing of another channel with a channel in bypass. The 12 hour time limit is justified in Reference 8.

P.1 and P.2

Condition P applies to the Turbine Trip on Stop Valve Closure. This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition. With one or more channels inoperable, the inoperable channels must be placed in the trip condition within 72 hours. Since all the valves must be tripped (not fully open) in order for the reactor trip signal to be generated, it is acceptable to place more than one Turbine Stop Valve Closure channel in the tripped condition. If a channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place an inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 8.

(continued)

ACTIONS (continued)

Q.1 and Q.2

Condition Q 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. This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours 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 Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have 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 RTB test are conducted within the 4 hour time limit. The 4 hour time limit is justified in Reference 8.

The 4 hour time limit for the RTS Automatic Trip Logic train testing is greater than the 2 hour time limit for the RTBs, which the Logic train supports. The longer time limit for the Logic train (4 hours) is acceptable based on Reference 10.

R.1 and R.2

Condition R applies to the P-6 interlock. With one or more channels inoperable for one-out-of-two coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed

(continued)

ACTIONS

R.1 and R.2 (continued)

in MODE 3 within the next 6 hours. 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. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

S.1 and S.2

Condition S applies to the P-7, P-8, P-9, P-10, 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 within 1 hour or THERMAL POWER must be reduced to less than the affected interlock setpoint within the next 6 hours. 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. 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 and T.2

Condition T 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 is allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 11. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in Condition C entry while RTBs are inoperable.

(continued)

ACTIONS

T.1 and T.2 (continued)

The Required Actions have been modified by a Note. The Note allows one train 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 11.

U.1 and U.2

Condition U 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 the unit must be placed in a MODE where Condition U is no longer applicable. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). 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. With the unit in MODE 3, Condition C applies to this trip function. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition T.

If two diverse trip features become inoperable in the same RTB, that RTB becomes inoperable upon discovery of the second inoperable trip feature.

The Completion Time of 48 hours for Required Action U.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.

(continued)

BASES

ACTIONS
(continued)

V.1

Condition V corresponds to a level of degradation in the RTS that causes a required safety function to be lost. When more than one Condition of this LCO is entered, and this results in the loss of automatic reactor trip capability, the unit is in a condition outside the accident analysis.

(continued)

ACTIONS

V.1 (continued)

Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

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 by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

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 power range channel output. If the calorimetric heat balance results exceed the power range channel output by more than +2% RTP, the power range channel is not declared inoperable, but must be adjusted consistent with the calorimetric heat balance results. If the power range channel output cannot be properly adjusted, the channel is declared inoperable.

If the calorimetric is performed at part power (< 50% RTP), adjusting the power range channel indication in the increasing direction will assure a reactor trip below the safety analysis limit of 118% RTP. Making no adjustment to the power range channel in the decreasing power direction due to a part-power calorimetric assures a reactor trip consistent with the safety analyses.

This allowance does not preclude making indication power adjustments, if desired, when the calorimetric heat balance calculation is less than the power range channel output. To provide close agreement between indicated and calorimetric power and to preserve operating margin, the power range channels are normally adjusted when operating at or near full power during steady-state conditions. However, discretion must be exercised if the power range channel output is adjusted in the decreasing power direction due to a part-power calorimetric (< 50% RTP). This action may introduce a nonconservative bias at higher power levels which may result in an NIS reactor trip above the safety analysis limit of 118% RTP. The cause of the potential nonconservative bias is the decreased accuracy of the calorimetric at reduced power conditions. The primary error

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

contributor to the instrument uncertainty for a secondary side power calorimetric measurement is the feedwater flow measurement which is typically a ΔP measurement across a feedwater venturi. While the measurement uncertainty remains constant in ΔP as power decreases, when translated into flow, the uncertainty increases as a square term. Thus a 1% flow error at 100% RTP can approach a 10% error at 30% RTP even though the ΔP error has not changed. An evaluation of extended operation at part-power conditions would conclude that it is prudent to administratively adjust the setpoint of the Power Range Neutron Flux – High bistables to ≤ 90% RTP for a calorimetric power determined below 50% RTP, and to ≤ 75% RTP for a calorimetric power determined below 20% RTP when: 1) the power range channel output is adjusted in the decreasing power direction due to a part-power calorimetric; or 2) for a post-refueling startup. While the part-power calorimetric uncertainty based on a feedwater flow measurement from the leading-edge flow meter (LEFM) is less than that based on the feedwater venturi, it is prudent to continue to apply the same adjustments to the setpoint.

Before the Power Range Neutron Flux – High bistables are reset to the nominal value in Table 3.3.1-1 of Specification 3.3.1, the power range channel adjustment must be confirmed based on a calorimetric performed at a power level ≥ 50% RTP.

The 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 core power distribution information to the NIS channel output.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

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 primarily performed to verify the (AFD) input to the overtemperature ΔT function.

SR 3.3.1.3 compares the incore system to the NIS channel output. 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 primarily performed to verify the f(AFD) input to the overtemperature ΔT function.

The Note clarifies that the Surveillance is required only if reactor power is ≥ 50% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 50% RTP.

Axial offset is the difference between the power in the top half of the core and the bottom half of the core expressed as a fraction (percent) of the total power being produced by the core. Mathematically, it is expressed as:

$$AO = 100 \times \frac{(Flux_T - Flux_B)}{(Power)(Flux_T + Flux_B)}$$

where $Flux_T$ = neutron flux at the top of the core, and

$Flux_B$ = neutron flux at the bottom of the core

The relationship between AFD and axial offset is:

$$AFD = AO \times (Power(\%)/100)$$

AFD as displayed on the main control board and as determined by the plant computer use inputs from the power range NIS detectors which are located outside the reactor vessel. Axial offset is measured using either the Power Distribution Monitoring System (PDMS) or movable incore detectors. For the performance of SR 3.3.1.3, WCAP-8648-A, *EXCORE Detector Recalibration Using Quarter-Core Flux Maps*, provides an acceptable method of measuring axial offset using incore detectors.

The surveillance assures that the AFD as displayed on the main control board and as determined by the plant computer is within 3% of the AFD as calculated from the axial offset equation. Agreement is required so that the reactor is operated within the bounds of the safety analysis regarding axial power distribution.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

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

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT on a STAGGERED TEST BASIS. 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 independence 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 on a STAGGERED TEST BASIS, 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.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the core power distribution information. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the core power distribution information. If the excore channels cannot be adjusted, the channels are declared inoperable. This surveillance is primarily performed to verify the f(AFD) input to the overtemperature ΔT function.

Two Notes modify SR 3.3.1.6. Note 1 states that this Surveillance is required only if reactor power is > 75% RTP and that 7 days is allowed for performing the first surveillance after reaching 75% RTP. Note 2 states that neutron detectors are excluded from the calibration.

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 conservative with respect to 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 drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as-found" and "as-left" values must also be recorded and reviewed for consistency with the assumptions of Reference 6.

This Surveillance Requirement is modified by two Notes that apply only to the Source Range instrument channels. Note 1 requires that the COT include verification that interlocks P-6 and P-10 are in the required state for the existing unit

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

conditions. Note 2 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 delay for the performance of this SR to meet the applicability requirements in Mode 3. This delay allows time to open the RTBs in Mode 3 after which this SR is no longer required to be performed. If the unit is to be in Mode 3 with the RTBs closed for greater than 4 hours, this surveillance must be completed prior to the expiration of the 4 hours.

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

SR 3.3.1.7 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

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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 the frequency is prior to reactor startup. This SR is not required to be met when reactor power is decreased below P-10 (10% RTP) or when MODE 2 is entered from MODE 1 during controlled shutdowns. The Surveillance is modified by a Note that specifies this surveillance can be satisfied by the performance of a COT within 31 days prior to reactor startup. This test ensures that the NIS source range, intermediate range, and power range low setpoint channels are OPERABLE prior to taking the reactor critical.

SR 3.3.1.8 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

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SURVEILLANCE REQUIREMENTS (continued)

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 unit 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. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

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.

SR 3.3.1.10 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service.

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SURVEILLANCE REQUIREMENTS (continued)

For channels determined to be OPERABLE but degraded, after returning the channel to service the channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

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 that states that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors includes a normalization of the detectors based on a power calorimetric and core power distribution information. The CHANNEL CALIBRATION for the source range neutron detectors includes obtaining the detector preamp discriminator curves and evaluating those curves.

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

SR 3.3.1.11 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.11 (continued)

returning the channel to service the channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a COT of RTS interlocks.

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

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of the Manual Reactor Trip and the SI Input from ESFAS. This TADOT is as described in SR 3.3.1.4.

The manual reactor trip TADOT shall independently verify the OPERABILITY of the undervoltage and shunt trip circuits for the manual reactor trip function. This test shall also verify the OPERABILITY of the Bypass breaker trip circuit(s), including the automatic undervoltage trip.

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

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.13 (continued)

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 the turbine stop valve closure Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed after each entry into MODE 3 for a unit shutdown and prior to exceeding the P-9 interlock trip setpoint. Note 1 states that this Surveillance is not required if it has been performed within the previous 31 days. Note 2 states that verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test ensures that the reactor trip on turbine trip Function is OPERABLE prior to entering the Mode of Applicability (above the P-9 power range neutron flux interlock) for this instrument function. The frequency is based on the known reliability of the instrumentation that generates a reactor trip after the turbine trips, and has been shown to be acceptable through operating experience.

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 FSAR, Chapter 7 (Ref. 1). 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 (i.e., control and shutdown rods fully inserted in the reactor core).

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 or with the time constants set to their nominal value. The results must be compared to properly defined acceptance criteria. The response time may be measured by a series of overlapping tests such that the entire response time is measured.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.15 (continued)

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 allocation 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) in place, onsite, or offsite (e.g., vendor) test measurements, or (3) using vendor engineering specifications. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” (Ref. 12), 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.

WCAP-14036-P Revision 1, “Elimination of Periodic Protection Channel Response Time Tests,” (Ref. 13), 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. 12 and Ref. 13, 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. 14).

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

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.15 (continued)

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.

SR 3.3.1.16

SR 3.3.1.16 is the performance of a COT for the low fluid oil pressure portion of the Turbine Trip Functions as described in SR 3.3.1.7 except that the Frequency is after each entry into MODE 3 for a unit shutdown and prior to exceeding the P-9 interlock trip setpoint. The surveillance is modified by two Notes. Note 1 states that the surveillance may be satisfied if performed within the previous 31 days. Note 2 states that verification of the setpoint is not required. Performance of this test ensures that the reactor trip on turbine trip function is OPERABLE prior to entering the Mode of Applicability (above the P-9 power range neutron flux interlock) for this instrument function. The frequency is based on the known reliability of the instrumentation that generates a reactor trip after the turbine trips, and has been shown to be acceptable through operating experience.

REFERENCES

1. FSAR, Chapter 7.

(continued)

BASES

REFERENCES (continued)

2. FSAR, Chapter 6.

3. FSAR, Chapter 15.

4. IEEE-279-1971.

5. 10 CFR 50.49.

6. WCAP-11269, Westinghouse Setpoint Methodology for Protection Systems; as supplemented by:

   - Amendments 34 (Unit 1) and 14 (Unit 2), RTS Steam Generator Water Level – Low Low, ESFAS Turbine Trip and Feedwater Isolation SG Water Level – High High, and ESFAS AFW SG Water Level – Low Low.
   - Amendments 48 and 49 (Unit 1) and Amendments 27 and 28 (Unit 2), deletion of RTS Power Range Neutron Flux High Negative Rate Trip.
   - Amendments 60 (Unit 1) and 39 (Unit 2), RTS Overtemperature ΔT setpoint revision.
   - Amendments 57 (Unit 1) and 36 (Unit 2), RTS Overtemperature and Overpower ΔT time constants and Overtemperature ΔT setpoint.
   - Amendments 43 and 44 (Unit 1) and 23 and 24 (Unit 2), revised Overtemperature and Overpower ΔT trip setpoints and allowable values.
   - Amendments 104 (Unit 1) and 82 (Unit 2), revised RTS Intermediate Range Neutron Flux, Source Range Neutron Flux, and P-6 trip setpoints and allowable values.
   - Amendments 127 (Unit 1) and 105 (Unit 2), revised Overtemperature ΔT trip setpoint to limit value of the compensated temperature difference and revised the modifier for axial flux difference.
   - Amendments 128 (Unit 1) and 106 (Unit 2), revised Overtemperature ΔT and Overpower ΔT trip setpoints to increase the fundamental setpoints K_1 and K_4, and to modify coefficients and dynamic compensation terms.
   - Amendments 149 (Unit 1) and 129 (Unit 2), revised P-9 setpoint and allowable value.

7. Westinghouse Letter GP-16696, November 5, 1997.

(continued)

BASES

REFERENCES (continued)

8. WCAP-14333-P-A, Rev. 1, October 1998.

9. WCAP-10271-P-A, Supplement 1, May 1986.

10. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

11. WCAP-15376-P-A, Rev. 1, March 2003.

12. WCAP-13632-P-A Revision 2, "Elimination of Periodic Sensor Response Time Testing Requirements," January 1996.

13. WCAP-14036-P-A Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.

14. 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. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the ESFAS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to include LSSS for variables that have significant safety functions. LSSS are defined by the regulation as "Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytical Limit is the limit of the process variable at which a protective action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The Nominal Trip Setpoint (NTSP) specified in Table 3.3.2-1 is a predetermined setting for a protection channel chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the NTSP accounts for uncertainties in setting the channel (e.g., calibration), uncertainties in how the channel might actually perform (e.g., repeatability), changes in the point of action of the channel over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the NTSP ensures that SLs are not exceeded. Therefore, the NTSP meets the definition of an LSSS (Ref. 1).

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety functions(s)." Relying solely on the NTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for

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BACKGROUND (continued)

the "as-found" value of a protection channel setting during a surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protection channel with a setting that has been found to be different from the NTSP due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the NTSP and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as-found" setting of the protection channel. Therefore, the channel would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the channel within the established as-left tolerance around the NTSP to account for further drift during the next surveillance interval.

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 SL value to prevent departure from nucleate boiling (DNB),

2. Fuel centerline melt shall not occur, and

3. The RCS pressure SL of 2750 psia shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs.

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 offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 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 ESFAS instrumentation is segmented into four 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;

(continued)

BACKGROUND (continued)

- 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 channels, 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.

- Sequencer output relays which change state upon the applicable ESFAS signal to energize ESF loads powered by the 4160-V ESF bus: these relays are required to change state upon the applicable ESFAS signal to energize ESF loads powered by the 4160-V ESF bus and in this way they function as ESFAS actuation relays.

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 NTSP 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 NTSPs derived from Analytical Limits established by the safety analyses. Analytical Limits are discussed in FSAR, Chapter 6 (Ref. 2), Chapter 7 (Ref. 3), and Chapter 15 (Ref. 4). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for

(continued)

BASES

BACKGROUND

Signal Processing Equipment (continued)

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 unit 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.

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. 5). The actual number of channels required for each unit parameter is specified in Reference 2.

NTSPs and Allowable Values

The setpoints used in the bistables are based on the analytical limits stated in Reference 3. The calculation of the Nominal Trip Setpoints specified in Table 3.3.2-1 is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Allowable Values and NTSPs, including their explicit uncertainties, is provided in the "RTS/ESFAS

(continued)

BACKGROUND

NTSPs and Allowable Values (continued)

Setpoint Methodology Study" (Ref. 7) which incorporates all of the known uncertainties applicable to each channel. The as-left tolerance and as-found tolerance band methodology is provided in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions. The magnitude of these uncertainties are factored into the determination of each NTSP and corresponding Allowable Value. The actual nominal setpoint entered into the bistable is more conservative than that specified by the NTSP to account for measurement errors detectable by a COT. The Allowable Value serves as the as-found Technical Specification OPERABILITY limit for the purpose of the COT.

The NTSP is the value at which the bistables are set and is the expected value to be achieved during calibration. The NTSP value is the LSSS and ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as-left" NTSP value is within the as-left tolerance for Channel Calibration uncertainty allowance (i.e., rack calibration and comparator setting uncertainties). The NTSP value is therefore considered a "nominal value" (i.e., expressed as a value without inequalities) for the purposes of the COT and CHANNEL CALIBRATION.

NTSPs in conjunction with the use of as-found and as-left tolerances together with the requirements of the Allowable Value ensure 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 DBA and the equipment functions as designed.

Note that the Allowable Values listed in Table 3.3.2-1 are the least conservative value of the as-found setpoint that a channel can have during a periodic CHANNEL CALIBRATION, COT, or a TADOT.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 3. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

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BACKGROUND (continued)

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 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 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 channels 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.

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BACKGROUND (continued)

Sequencer Output Relays

The sequencer output relays which change state to actuate ESF loads powered by the 4160-V ESF bus function as ESFAS actuation relays because these relays are required to function to energize the ESF loads. These particular relays are located in the termination and relay cabinets of the sequencer and are part of the control circuitry of these ESF loads. There are two independent trains of sequencers and each is powered by the respective train of 120-Vac ESF electrical power supply. The power supply for the output relays is the sequencer power supply. The applicable output relays are tested in the slave relay testing procedures, and in particular, in conjunction with the specific slave relay also required to actuate to energize the applicable ESF load.

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 implicitly 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).

Permissive and interlock setpoints allow the blocking of trips during plant startups, and restoration of trips when the permissive conditions are not satisfied, but they are not explicitly modeled in the Safety Analyses. These permissives and interlocks ensure that the starting conditions are consistent with the safety analysis, before preventive or mitigating actions occur. Because these permissives or interlocks are only one of multiple conservative starting assumptions for the accident analysis, they are generally considered as nominal values without regard to measurement accuracy.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an ESFAS Function listed in Table 3.3.2-1 in the accompanying LCO to be OPERABLE. The Allowable Value specified in Table 3.3.2-1 is the least conservative value of the as-found setpoint that the channel can have when tested, such that a channel is OPERABLE if the as-found setpoint is within the as-found tolerance and is conservative with respect to the Allowable Value during the CHANNEL CALIBRATION or CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the NTSP by an amount greater than or equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the channel (NTSP) will ensure that a SL is not exceeded at any given point of time as long as the channel has not drifted beyond expected tolerances during the surveillance interval. Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the as-left tolerance, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned (as-found criteria).

If the actual setting of the channel is found to be conservative with respect to the Allowable Value but is beyond the as-found tolerance band, the channel is OPERABLE but degraded. The degraded condition of the channel will be further evaluated during performance of the SR. This evaluation will consist of resetting the channel setpoint to the NTSP (within the allowed tolerance) and evaluating the channel response. If the channel is functioning as required and expected to pass the next surveillance, then the channel can be restored to service at the completion of the surveillance.

A trip setpoint may be set more conservative than the NTSP as necessary in response to plant conditions. However, in this case, the operability of this instrument must be verified based on the field setting and not the NTSP. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

The LCO generally requires OPERABILITY of four or three 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. If an instrument channel is equipped with installed bypass capability, such that no jumpers or lifted leads are required to place the channel in bypass and annunciation of the bypass condition is available in the control room, corrective maintenance and testing of that channel may be performed in the bypass condition. Bypassing a channel renders that channel inoperable and the associated Required Actions for that channel are applicable. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

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 (k_{eff} < 1.0).

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;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps; and

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

- Control room ventilation isolation.

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Isolation of the control room to ensure habitability.

In addition, safety injection also initiates component cooling water, emergency diesel generators, containment cooling fans, and nuclear service cooling water.

All of the above items are credited with response times in the accident analyses. Two functions which safety injection initiates but which are not credited with response times are turbine trip and enabling semi-automatic switchover of Emergency Core Cooling System (ECCS) suction to containment sump.

a. Safety Injection - Manual Initiation

The LCO requires two channels to be OPERABLE. 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 both trains in the same manner as would the automatic actuation signals on both trains of SSPS.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Safety Injection - Manual Initiation (continued)

circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one handswitch and the interconnecting wiring to the actuation logic cabinets of both SSPS trains. Each handswitch actuates both trains. This configuration does not allow testing at power.

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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic and actuation relay function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

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 a SI, actuation is simplified by the use of the manual actuation handswitches. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Safety Injection - Automatic Actuation Logic and Actuation Relays (continued)

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.

c. Safety Injection - Containment Pressure — High 1

(PI-0934, PI-0935, PI-0936)

NOTE: Containment pressure channels are also required OPERABLE by the Post Accident Monitoring Technical Specification.

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 NTSP 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Safety Injection - Pressurizer Pressure — Low

This signal (PI-0455A, B, & C, PI-0456, PI-0456A, PI-0457, PI-0457A, PI-0458 & PI-0458A) provides protection against the following accidents:

- Inadvertent opening of a steam generator (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: input to the Pressurizer Pressure Control System, reactor trip, and SI. Therefore, the actuation logic must be able to withstand both an input failure to 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 NTSP reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Safety Injection - Pressurizer Pressure — Low (continued)

be manually blocked by the operator below the P - 11 setpoint. Automatic SI actuation below this pressure setpoint continues to be performed by the Containment — 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

LOOP 1	LOOP 2	LOOP 3	LOOP 4
PI-0514A,B&C	PI-0524A&B	PI-0534A&B	PI-0544A,B&C
PI-0515A	PI-0525A	PI-0535A	PI-0545A
PI-0516A	PI-0526A	PI-0536A	PI-0546A

NOTE: Steam Line Pressure channels are also required OPERABLE by the Post Accident Monitoring Technical Specification.

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 no input to any control functions. 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 located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the NTSP reflects both steady state and adverse environmental instrument uncertainties.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Safety Injection - Steam Line Pressure — Low (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 to cause an accident.

2. Containment Spray

Containment Spray provides two primary functions:

1. Lowers containment pressure and temperature after an HELB in containment; and

2. Reduces the amount of radioactive iodine in the containment atmosphere.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure; and

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure.

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. When the RWST reaches the Tank Empty setpoint 8%, the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Containment Spray (continued)

spray pump suctions are manually switched over to the containment sump if continued containment spray is required. Containment spray is actuated manually or by Containment Pressure — High 3.

a. Containment Spray - Manual Initiation

The operator can initiate both trains of containment spray at any time from the control room by simultaneously turning the two containment spray actuation handswitches 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 a channel of CS Manual Initiation. Simultaneously turning the two switches in either channel will actuate both trains of containment spray. Two Manual Initiation switches in each channel are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function.

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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic and actuation relays function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Containment Spray - Automatic Actuation Logic and Actuation Relays (continued)

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 handswitches. 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. Containment Spray - Containment Pressure High — 3

(PI-0934, PI-0935, PI-0936, PI-0937)

NOTE: Containment Pressure Channels are also required OPERABLE by the Post Accident Monitoring Technical Specification.

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, they will not experience any adverse environmental conditions and the NTSP 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Containment Spray - Containment Pressure High — 3 (continued)

The Containment Pressure High-3 instrument Function consists of four channels 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 setpoints.

3. Phase A Containment Isolation

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation logic.

a. Phase A Isolation — Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two switches in the control room. Either switch actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

b. Phase A 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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic function be

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Phase A Isolation — Automatic Actuation Logic and Actuation Relays (continued)

declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

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 handswitches. 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. 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.

c. 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.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Steam Line Isolation

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 main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident. Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

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 required in MODES 2 and 3

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Steam Line Isolation (continued)

unless one MSIV and associated bypass valve in each steam line is 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.

c. Steam Line Isolation — Containment Pressure — High 2

(PI-0934, PI-0935, PI-0936)

NOTE: Containment Pressure channels are also required OPERABLE by the Post Accident Monitoring Technical Specification.

This Function actuates closure of the MSIVs 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) are located outside containment with the sensing line (high pressure side of the transmitter) located inside containment. Thus, they will not experience any adverse environmental conditions, and the NTSP reflects only steady state instrument uncertainties. 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.

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. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless one MSIV and associated bypass valve in each steam line is closed. In

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation — Containment Pressure — High 2 (continued)

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

LOOP 1	LOOP 2	LOOP 3	LOOP 4
PI-0514A,B&C	PI-0524A&B	PI-0534A&B	PI-0544A,B&C
PI-0515A	PI-0525A	PI-0535A	PI-0545A
PI-0516A	PI-0526A	PI-0536A	PI-0546A

NOTE: Steam Line Pressure channels are also required OPERABLE by the Post Accident Monitoring Technical Specification.

Steam Line Pressure — Low provides closure of the MSIVs 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. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure — Low was discussed previously under SI Function 1.e.1.

Steam Line Pressure — Low Function must be OPERABLE in MODES 1, 2, and 3 (above P - 11), except with one MSIV and associated bypass valve in each steam line closed, 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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(1) Steam Line Pressure — Low (continued)

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 OPERABLE in MODES 2 and 3 unless one MSIV and associated bypass valve in each steam line is 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 to have an accident.

(2) Steam Line Pressure — Negative Rate — High

LOOP 1	LOOP 2	LOOP 3	LOOP 4
PI-0514A, B&C	PI-0524A&B	PI-0534A&B	PI-0544A, B&C
PI-0515A	PI-0525A	PI-0535A	PI-0545A
PI-0516A	PI-0526A	PI-0536A	PI-0546A

NOTE: Steam Line Pressure channels are required OPERABLE by the Post Accident Monitoring Technical Specification.

Steam Line Pressure — Negative Rate — High provides closure of the MSIVs 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.

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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

(2) Steam Line Pressure — Negative Rate — High (continued)

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 enabled. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless one MSIV and associated bypass valve in each steam line is 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 significant enough quantities of energy to cause a 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 NTSP reflects only steady state instrument uncertainties.

5. Turbine Trip and Feedwater Isolation

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.

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 taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Turbine Trip and 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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

b. Feedwater Isolation — Low RCS T_{avg} Coincident with Reactor Trip

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. Thus, this function is specified as a total of four channels and not on a per loop basis. The channels are used in a two-out-of-four logic. The Low RCS T_{avg} signal 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 generated power. The P-4 interlock is discussed in Function 8.a.

c. Turbine Trip and Feedwater Isolation — Steam Generator Water Level — High High (P-14)

LOOP 1	LOOP 2	LOOP 3	LOOP 4
LI-0517	LI-0527	LI-0537	LI-0547
LI-0518	LI-0528	LI-0538	LI-0548
LI-0519	LI-0529	LI-0539	LI-0549
LI-0551	LI-0552	LI-0553	LI-0554

NOTE: Steam Generator Water Level channels are required OPERABLE by the Post Accident Monitoring Technical Specification.

The setpoints for this Function on Table 3.3.2-1 are in % of narrow range instrument span.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Turbine Trip and Feedwater Isolation — Steam Generator Water Level — High High (P-14) (continued)

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 are required to satisfy the requirements with a two-out-of-four logic.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause an adverse environment in containment. Therefore, the NTSP Setpoint reflects only steady state instrument uncertainties.

d. 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 MODES 1 and 2 except when one MFIV or MFRV and associated bypass valve per feedwater line are closed and deactivated or isolated by a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 3, 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of ac power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST). The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater — Automatic Actuation Logic and Actuation Relays (Solid State Protection System)

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

b. Auxiliary Feedwater — Steam Generator Water — Low Low

LOOP 1	LOOP 2	LOOP 3	LOOP 4
LI-0517	LI-0527	LI-0537	LI-0547
LI-0518	LI-0528	LI-0538	LI-0548
LI-0519	LI-0529	LI-0539	LI-0549
LI-0551	LI-0552	LI-0553	LI-0554

NOTE: Steam Generator Water Level channels are required OPERABLE by the Post Accident Monitoring Technical Specification.

The setpoints for this Function on Table 3.3.2-1 are in % of narrow range instrument span.

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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Auxiliary Feedwater — Steam Generator Water Level — Low Low (continued)

MFW, 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 are required to satisfy the requirements with two-out-of-four logic. SG Water Level — Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level — Low Low in any two operating SGs will cause the turbine driven pump to start.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the NTSP reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater — Safety Injection

An SI signal starts the motor driven AFW pumps. The AFW 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.

Functions 6.a through 6.c must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Auxiliary Feedwater (continued)

remove decay heat or sufficient time is available to manually place either system in operation.

d. Auxiliary Feedwater-Trip Of All Main Feedwater Pumps

A Trip of all MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MFW pump is equipped with a pressure switch on the control oil header. A low pressure signal from this pressure switch indicates a trip of that pump. A trip of all MFW pumps starts the motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.d must be OPERABLE in MODES 1 and 2 when the MFW system is operating and supplying the SGs. 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 MODE 2, when the MFW system is not supplying the SGs, this function is not required as the AFW system is operating to supply the SGs and does not require the auto start from this function. In MODES 3, 4, and 5, the RCPs and MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW initiation.

7. Semi-Automatic Switchover to Containment Sump

At the end of the 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Semi-Automatic Switchover to Containment Sump (continued)

heat exchanger, inject the water back into the RCS, and supply the cooled water to the other ECCS pumps. Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the RHR 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 ESF 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.

a. Semi-Automatic 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. Under specific conditions, a single inoperable actuation relay does not require that the affected automatic actuation logic function be declared inoperable. Specific guidance is provided in this section under the heading "Actuation Relays."

b. Semi-Automatic Switchover to Containment Sump — Refueling Water Storage Tank (RWST) Level — Low Low Coincident With Safety Injection

(LI-0990A&B, LI-0991A&B, LI-0992A, LI-0993A)

NOTE: RWST Level channels are also required OPERABLE by the Post Accident Monitoring Technical Specification. In addition channels LI-0990 and 0991 provide actuation signals to the RWST sludge mixing pump isolation valves required OPERABLE by LCO 3.5.4.

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 start of the ECCS and CS switchover process. The containment sump to RHR pump suction valves open

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Automatic Switchover to Containment Sump — Refueling Water Storage Tank (RWST) Level — Low Low Coincident With Safety Injection (continued)

automatically. The operator must complete the ECCS switchover by manually closing the RWST to RHR pump suction valves between the RWST empty level and RWST height of 2.515 ft. The operator must complete the CS switchover by manually closing the RWST to CS pump suction valves between the RWST empty level and dead volume.

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 setpoints for this function on Table 3.3.2-1 are in inches from the RWST base. The NTSP is equivalent to 29.0% of instrument span, including instrument uncertainty. The Allowable Values are equivalent to ≥ 28.5% and ≤ 29.5 % of instrument span.

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 NTSP reflects only steady state instrument uncertainties.

Semi-Automatic switchover 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 automatic 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.

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

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Automatic Switchover to Containment Sump — Refueling Water Storage Tank (RWST) Level — Low Low Coincident With Safety Injection (continued)

the ECCS pumps. In MODE 4, only one train of Automatic Actuation Logic and Actuation Relays is required OPERABLE to support the single RHR train required OPERABLE in this MODE. 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 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.

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 are open. Once the P-4 interlock is enabled, automatic SI initiation can be 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 (all loads are started). Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed. The safety functions of the P-4 interlock are:

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Engineered Safety Feature Actuation System Interlocks — Reactor Trip, P-4 (continued)

- Trip the main turbine;
- Isolate MFW with coincident low T_{avg};
- Prevent reactuation of SI after a manual reset of SI; and
- Prevent opening of the MFW 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 generated 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.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. 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 four Functions associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are not exceeded.

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a NTSB and Allowable Value. The interlock is armed when the RTB (RTA or RTB) or associated bypass breaker (BYA or BYB) is closed in each Train.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Engineered Safety Feature Actuation System Interlocks — Reactor Trip, P-4 (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical, approaching criticality, or the automatic SI function is required to be OPERABLE. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, the MFW System, and the automatic SI function are not required to be OPERABLE. The P-4 function to trip the turbine and isolate main feedwater are only required in MODES 1 and 2 when these systems may be in service.

b. Engineered Safety Feature Actuation System Interlocks — Pressurizer Pressure, P-11

The P-11 interlock (PT-0455, PT-0456, PT-0457) permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels (discussed previously) 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. 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. The NTSP

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Engineered Safety Feature Actuation System Interlocks — Pressurizer Pressure, P-11 (continued)

reflects only steady state instrument uncertainties.

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.

ACTUATION RELAYS

If the inoperability of one or more slave relays affects only one train of an ESF system function, and if the integrated system response that accomplishes the design safety function of the applicable engineered safety feature is maintained given the inoperability of the slave relay(s), then the TS requirements to be applied may be limited to those of the applicable system specification. If more than one ESF system function is affected, or the integrated system response is affected, then the automatic actuation logic and actuation relays TS requirements must be applied, in addition to any necessary system TS requirements.

The purpose of ESFAS actuation logic and relays is to initiate the integrated system response that accomplishes the design safety function of the applicable engineered safety feature (ESF). Slave relays actuate individual components within systems that comprise the various ESFs. The application of slave relays varies from actuation of a single component within a system to multiple components that are shared among systems, and hence, the inoperability of a slave relay could impact one or more components that perform functions in one or more ESFs.

If the relay in question functions to provide the integrated system response of an ESF, then the TS requirements applicable to the ESFAS actuation logic and relays must be applied. Also, if the relay in question impacts more than one ESF system function, then the TS requirements applicable

(continued)

ACTUATION RELAYS (continued)

to the ESFAS actuation logic and relays must be applied. In these cases, depending on the operability requirements of the applicable system specification(s), the applicable system TS requirements may also be necessary.

If the results of a slave failure on a system performing ESF functions are no more severe than a limited equipment inoperability within that system, then the failure does not conflict with the actuation logic and relays TS requirements because the ability to initiate the integrated system response for the ESF is maintained. In this case, the failure of the slave relay would result only in the loss of the ability to actuate limited aspects of a system, where the collective impact of the slave relay inoperability would be no more severe than the inoperability of the one or more affected components of the system in question. The appropriate TS requirements to be applied under these conditions are limited to those of the system specification(s). The loss of that ability due to the slave relay inoperability must be completely within the system conditions provided for by the TS, whether in the statement of the LCO or in the allowed outage configuration(s) as provided in the action statements.

For example, if a slave relay inoperability affected only the Train A containment spray pump, this condition would be no more severe than the pump being inoperable. In this case, Train A of containment spray should be declared inoperable and the TS requirements for an inoperable train of containment spray should be applied. In this case it would be unnecessarily conservative to apply the 6 hour AOT. The application of the 6 hour AOT could result in an unnecessary shutdown and the associated plant transient and increased risk of operating events associated with plant transients.

Therefore, if the inoperability of one or more slave relays affects only one train of an ESF system function, and if the integrated system response that accomplishes the design safety function of the applicable ESF is maintained given the inoperability of the slave relay(s), then the TS requirements to be applied may be limited to those of the appropriate system specification. If more than one ESF system function is affected, or the integrated system

(continued)

ACTUATION RELAYS (continued)

response is affected, then the actuation logic and actuation relay TS requirements should be applied, in addition to any necessary system TS requirements.

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

ACTIONS

In the event a channel's NTSP is found nonconservative with respect to the Allowable Value, or the channel is not functioning as required, 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 (e.g., 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.

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 3.3.2-1.

When the number of inoperable channels in a trip function exceed those specified in one or other 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.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels 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.

(continued)

ACTIONS (continued)

B.1, B.2.1, and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray; and
- Phase A Isolation.

This action addresses the channel orientation of the SSPS for the functions listed above. If a channel is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray, failure of one or both handswitches 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 channel OPERABLE for each Function, and the low probability of an event occurring during this interval. If the channel cannot be restored to OPERABLE status, the unit must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 4 within an additional 6 hours (60 hours total time). Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 18). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 18, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptablilty of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The allowable Completion Times are

(continued)

ACTIONS

B.1, B.2.1, and B.2.2 (continued)

reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Semi-Automatic Switchover to Containment Sump.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

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. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 8. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within an additional 6 hours (30 hours total time) and in MODE 4 within an additional 6 hours (36 hours total time). Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 18). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides

(continued)

ACTIONS

C.1, C.2.1, and C.2.2 (continued)

diversity and defense in depth. As stated in Reference 18, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2.2 is modified by a Note that states that LCO 3.0.4a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing or maintenance, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 9) that 4 hours is the average time required to perform train surveillance.

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure — High 1;
- Pressurizer Pressure — Low;
- Steam Line Pressure — Low;
- Containment Pressure — High 2;

(continued)

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

- Steam Line Pressure — Negative Rate — High; and
- SG Water level — Low Low.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three 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-three 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 8.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 8.

E.1, E.2.1, and E.2.2

Condition E applies to:

(continued)

BASES

ACTIONS

E.1, E.2.1, and E.2.2 (continued)

- Containment Spray Containment Pressure — High 3.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

This signal does not 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. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray, 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 high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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, this Function is no longer required OPERABLE.

(continued)

ACTIONS

E.1, E.2.1, and E.2.2 (continued)

The Required Actions are modified by a Note that, with one channel inoperable, allows routine surveillance testing of another channel with a channel in bypass for up to 12 hours. Placing a second channel in the bypass condition for up to 12 hours for testing purposes is acceptable based on the results of Reference 8.

F.1, F.2.1, and F.2.2

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 channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the channel cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 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 unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

G.1, G.2.1, and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of

(continued)

BASES

ACTIONS

G.1, G.2.1, and G.2.2 (continued)

service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

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. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 8. 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.

If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

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 channel is OPERABLE. This allowance is based on the reliability analysis (Ref. 9) assumption that 4 hours is the average time required to perform channel surveillance.

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Turbine Trip and Feedwater Isolation Function.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in

(continued)

ACTIONS

H.1 and H.2 (continued)

the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 8. 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 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. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing or maintenance provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 9) assumption that 4 hours is the average time required to perform channel surveillances.

I.1 and I.2

Condition I applies to:

- SG Water Level — High High (P-14).

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in

(continued)

ACTIONS

I.1 and I.2 (continued)

the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-three logic will result in actuation. The 72 hours allowed to restore one channel to OPERABLE status or to place it in the tripped condition is justified in Reference 8. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 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, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The 12 hour time limit is justified in Reference 8.

J.1 and J.2

Condition J applies to the AFW pump start on trip of all MFW pumps.

This action addresses the train orientation for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to an OPERABLE status. If the function cannot be returned to an OPERABLE status, 6 hours are allowed to place the unit in MODE 3. 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, the unit does not have any analyzed

(continued)

ACTIONS

J.1 and J.2 (continued)

transients or conditions that require the explicit use of the protection function noted above. The allowance of 48 hours to return the train to an OPERABLE status is justified in Reference 9.

K.1, K.2.1, and K.2.2

Condition K applies to:

- RWST Level — Low Low Coincident with Safety Injection.

This Condition contains bypass times and Completion Times that are risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer based tool that may be used to aid in the risk assessment of on-line maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition.

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. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure 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 high). The 72 hour Completion Time is justified in Reference 8. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours, the unit must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

(continued)

ACTIONS

K.1, K.2.1, and K.2.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 18). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 18, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action K.2.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The 12 hour time limit is justified in Reference 8.

L.1, L.2.1, and L.2.2

Condition L applies to the P-11 interlock.

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.

(continued)

ACTIONS

L.1, L.2.1, and L.2.2 (continued)

Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

Agreement criteria are determined by the unit staff, 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.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested on a STAGGERED TEST BASIS, 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. Any change in the scope or frequency of this SR requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

SR 3.3.2.3

SR 3.3.2.3 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 time allowed for the testing on a STAGGERED BASIS (4 hours) is justified in Reference 9. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the scope or frequency of this SR requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4

SR 3.3.2.4 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 conservative with respect to 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 drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as-found" and "as-left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7.

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

SR 3.3.2.4 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program.

Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.4 (continued)

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

SR 3.3.2.5

SR 3.3.2.5 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. Any change in the scope or frequency of this SR requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. 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 for manual initiation Functions. The manual initiation Functions have no assumed setpoints.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 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 unit 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. The steam line pressure-low and steam line pressure negative rate-high functions have time constants specified in their setpoints.

SR 3.3.2.4 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be returned to within the as-left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the NTSP, then the channel shall be declared inoperable.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

The second Note also requires that the methodologies for calculating the as-left and the as-found tolerances be in NMP-ES-033-006, Vogtle Setpoint Uncertainty Methodology and Scaling Instructions.

SR 3.3.2.8

This SR ensures 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 FSAR, Chapter 7 (Ref. 3). 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 in both trains 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 or with the time constants set to their nominal value. The results must be compared to properly defined acceptance criteria. 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) using vendor engineering specifications. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements” (Reference 11), 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.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.8 (continued)

WCAP-14036-P Revision 1, “Elimination of Periodic Protection Channel Response Time Tests” (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 response time may be verified for components that replace the components that were previously evaluated in Ref. 11 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. 19).

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

This SR is modified by a Note that clarifies that the turbine driven AFW pump is tested within 24 hours after reaching 900 psig in the SGs.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a TADOT as described in SR 3.3.2.6 for the P-4 Reactor Trip Interlock, and the Frequency is once per 18 months. This Frequency is based on operating experience. The SR is modified by a note that excludes verification of setpoints during the TADOT. The function tested has no associated setpoint.

REFERENCES

1. Regulatory Guide 1.105, “Setpoints for Safety Related Instrumentation,” Revision 3.

2. FSAR, Chapter 6.

(continued)

REFERENCES (continued)

3. FSAR, Chapter 7.

4. FSAR, Chapter 15.

5. IEEE-279-1971.

6. 10 CFR 50.49.

7. WCAP-11269, Westinghouse Setpoint Methodology for Protection Systems; as supplemented by:

   - Amendments 38 (Unit 1) and 18 (Unit 2), ESFAS Safety Injection Pressurizer — Low allowable value revision.

   - Amendments 34 (Unit 1) and 14 (Unit 2), RTS Steam Generator Water Level — Low Low, ESFAS Turbine Trip and Feedwater Isolation SG Water Level — High High, and ESFAS AFW SG Water Level — Low Low.

   - Amendments 43 and 44 (Unit 1) and 23 and 24 (Unit 2), revised ESFAS Interlocks Pressurizer P-11 trip setpoint and allowable value.

8. WCAP-14333-P-A, Rev. 1, October 1998.

9. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

10. WCAP-15376-P-A, Rev. 1, March 2003.

11. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” January 1996.

12. WCAP-14036-P-A Revision 1, “Elimination of Periodic Protection Channel Response Time Tests,” October 1998.

13. Westinghouse Letter GP-16696, November 5, 1997.

14. WCAP-13878-P-A Revision 2, “Reliability Assessment of Potter & Brumfield MDR Series Relays,” April 1996.

15. WCAP-13900 Revision 0, “Extension of Slave Relay Surveillance Test Intervals,” April 1994.

16. WCAP-14129 Revision 1, “Reliability Assessment of Westinghouse Type AR Relays used as SSPS Slave Relays,” January 1999.

17. STI Evaluation 417332.

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BASES

REFERENCES (continued)

18. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

19. 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 unit 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 unit 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.

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;

(continued)

BASES

BACKGROUND (continued)

- 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 unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

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, preplanned, 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- 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). Category I, non-Type A, instrumentation must be retained in TS 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.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit 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 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 installed if the unit specific Regulatory Guide 1.97 analyses (Ref. 1) 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.

(continued)

BASES

LCO (continued)

Table 3.3.3-1 lists all Type A and Category I variables identified by the unit specific Regulatory Guide 1.97 analyses, as amended by the NRC's SER.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) 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.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure (LOOP 408, 418, 428, and 438) is a Category I Type A variable provided for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify delivery of 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 subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. 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 low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and

(continued)

BASES

LCO

1. Reactor Coolant System Pressure (Wide Range) (continued)

- 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.

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 also 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. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

(Hot Leg Loops 413A, 423A, 433A, & 443A)
(Cold Leg Loops 413B, 423B, 433B, & 443B)

RCS Hot and Cold Leg Temperatures are Category I, Type A variables provided for verification of core cooling and long term surveillance.

(continued)

BASES

LCO

2,3. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range) (continued)

RCS hot and cold leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (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.

Reactor outlet temperature inputs to the Reactor Protection System are provided by two fast response resistance elements and associated transmitters in each loop. The channels provide indication over a range of 50°F to 700°F.

The core exit thermocouples provide diverse indication for the RCS hot leg temperature.

Steam line pressure provides diverse indication for the RCS cold leg temperature.

4. Steam Generator Water Level (Wide Range)

Wide range SG water level (Loops 501, 502, 503, & 504) 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 the diverse indication for wide range SG water level.

(continued)

BASES

LCO
(continued)

5. Steam Generator Water Level (Narrow Range)

Narrow range SG water level (Loops 517-519, 527-529, 537-539, & 547-549) 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.

6. Pressurizer Level

Pressurizer Level (Loops 459, 460, & 461) 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.

7,20. Containment Pressure and Containment Pressure (Extended Range)

(Containment Pressure Type A Loops 934, 935, 936, & 937; Containment Pressure extended range loops 10942 & 10943)

Containment Pressure is provided for verification of RCS and containment OPERABILITY.

Containment pressure is also used to verify closure of main steam isolation valves (MSIVs) actuation of containment spray, and for accident diagnosis.

8. Steam Line Pressure

Steam Line Pressure (Loops 514, 515, 516, 524, 525, 526, 534, 535, 536, 544, 545, & 546) is a Type A variable provided for the following:

- Determining if a high energy secondary line rupture occurred and which steam generator is faulted;

(continued)

BASES

LCO

8. Steam Line Pressure (continued)

- Maintaining an adequate reactor heat sink;
- Verifying Auxiliary Feedwater flow to the faulted steam generator is isolated;
- Verifying operation of pressure control steam dump system;
- Maintaining the plant in a cold shutdown condition;
- Monitoring the RCS cooldown rate; and
- Providing diverse indication to Cold Leg temperature for natural circulation determination.

Three channels per steam line are installed with sufficient accuracy to determine the faulted steam generator and to verify Cold Leg temperature for natural circulation.

9. Refueling Water Storage Tank (RWST) Level

The RWST level (Loops 990, 991, 992, & 993) is a Type A variable provided for verifying a water source to the Emergency Core Cooling Systems (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 safety injection and 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 sump recirculation phase and ensure sufficient water is available to avoid losing pump suction.

(continued)

BASES

LCO (continued)

10,11. Containment Sump Water Level (Narrow and Wide Range)

Containment Sump Water Level (Narrow range Loops 7777 & 7789; wide range Loops 0764 & 0765) is a Type A variable provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used to determine:

- containment sump level accident diagnosis;
- when to begin the recirculation procedure; and
- whether to terminate SI, if still in progress.

12. Condensate Storage Tank (CST) Level

CST Level (Loops 5101, 5111, 5104, & 5116) is a Type A variable provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System. The CST consists of two identical tanks with separate piping to each AFW pump suction. Inventory is monitored by two 0-100% level indication channels for each tank. CST Level is displayed on a control room indicator, strip chart recorder, and unit computer. In addition, a control room annunciator alarms on low level.

The CST Level is considered a Type A variable because the control room meter and annunciator are considered the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST.

This function is modified by a Note that clarifies only one of the two CSTs must have two channels of level indication. Since only one CST is required OPERABLE, only one set of level channels is required. On Unit 2, due to the removal of the RHR bypass line with LDCR 2006011, both CSTs are required to be operable, therefore, both sets of level channels are required to be operable.

(continued)

BASES

LCO (continued)

13. Auxiliary Feedwater Flow

AFW Flow (Loops 5152, 15152, 5153, 15153, 5151, 15151, 5150, & 15150) is a Type A variable provided to monitor operation of decay heat removal via the SGs. The AFW Flow to each SG is determined from a differential pressure measurement calibrated for a range of 0 gpm to 1000 gpm. Redundant monitoring capability is provided by two independent trains of instrumentation for each SG. Each differential pressure transmitter provides an input to a control room indicator and the unit computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is a Type A variable because operator action is required to throttle flow during an SLB accident to prevent the AFW pumps from operating in runout conditions. AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

14. Containment Radiation (High Range)

Containment Area Radiation (Loops 0005 & 0006) is a Type A variable 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.

(continued)

LCO

14. Containment Radiation (High Range) (continued)

Containment radiation level is used to determine if a high energy line break (HELB) has occurred, and whether the event is inside or outside of containment.

15. Steam Line Radiation Monitors

The Steam Line Radiation Monitors (Loops 13119, 13120, 13121 & 13122) are a Type A variable provided to allow detection of a gross secondary side radioactive release and to provide a means to identify the faulted steam generator. Steam generator narrow range level serves as diverse indication for the one monitor per loop provided.

16. RCS Subcooling

RCS Subcooling is a Type A variable provided to determine safety injection termination and re-initiation. The RCS Subcooling variable is determined by calculation in the Plant Safety Monitoring System. The RCS Subcooling instrumentation provides the information that allows operators to ensure safety injection is terminated at the optimum time and that sufficient subcooling margin exists upon return to normal plant conditions. A minimum of four core exit thermocouples (CETs) in at least one quadrant is required. Also refer to Functions 22-25 and Bases 3.3.4 Function 5 for additional requirements on CETs.

17. Neutron Flux (Extended Range)

Neutron Flux (Loops 13135A & 13135B) indication is provided to verify reactor shutdown. The extended range is necessary to cover the full range of flux that may occur post accident.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

(continued)

BASES

LCO (continued)

18. Reactor Vessel Water Level

Reactor Vessel Water Level (LT1310, LT1311, LT1312, LT1320, LT1321, & LT1322) 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. A RVLIS channel consists of Full Range, Upper Range, and Dynamic Range transmitters. LT1310 and LT1320 are Upper Range, LT1311 and LT1321 are Full Range, and LT1312 and LT1322 are Dynamic Range.

The Reactor Vessel Water Level Monitoring System provides a direct measurement of the collapsed liquid level above the uppercore plate. The collapsed level represents the amount of liquid mass that is in the reactor vessel above the core. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory.

21. Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A isolation.

When used to verify Phase A isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active containment isolation valve in a containment penetration flow path, i.e., two total channels of containment isolation valve position indication for a penetration flow path with two active valves. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position

(continued)

BASES

LCO

21. Containment Isolation Valve Position (continued)

indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Note (b) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. The note also identifies the applicable valves (those valves receiving a Phase A or Containment Ventilation Isolation signal). Note C allows an exception to the LCO requirement (2/penetration) to be made for penetration flow paths with only one installed control room indication channel.

22, 23, 24, 25. Core Exit Temperature

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 (CET) necessary for measuring core cooling. The evaluation determined the reduced complement of CETs 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. Based on these evaluations, adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant with two CETs per required channel. The CET pair are oriented radially to permit evaluation of core radial decay power distribution. 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.

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of

(continued)

BASES

LCO 22, 23, 24, 25. Core Exit Temperature (continued)

radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. The two thermocouples in each channel must be located such that the pair of Core Exit Temperatures indicate the radial temperature gradient across their core quadrant. A Note specifies that each channel consists of two CETs. Two sets of two thermocouples ensure a single failure will not disable the ability to determine the radial temperature gradient. As such one required channel per quadrant must consist of two A train CETs and the other required channel per quadrant must consist of two B train CETs. Also refer to Function 16 and Bases 3.3.4 Function 5 for additional requirements on CETs.

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.

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.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies to all PAM Instrument Functions. Conditions A addresses the situation where one or more required channels for one or more Functions are inoperable. The Required Action is to refer to Table 3.3.3-1 and take the appropriate Required Actions for the PAM instrumentation affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, C.1, D.1, E.1, and F.1

These Conditions apply to PAM Instrument Functions when a single required channel is inoperable and a redundant or diverse channel for the affected function remains OPERABLE. Conditions C, D, E, and F each identify the specific acceptable diverse indication channel that is required OPERABLE for the affected PAM function. Condition B applies to those functions with redundant channels except for Containment Isolation Valves. Condition B is modified by a Note that applies to the containment isolation valve position indication function which allows separate Condition entry for that function based on penetration flow paths. This note clarifies that Condition B may be applied to the containment isolation valve position indication function separately for each penetration flow path.

Required Actions B.1, C.1, D.1, E.1, and F.1 require that the affected channel 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 redundant or diverse 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.

G.1

Condition G applies when the Required Action and associated Completion Time for Conditions B, C, D, E, or F are not met. This Required Action specifies initiation of actions in Specification 5.6.8, "Special Reports," which require a written report, approved by the Plant Review Board (PRB), to

(continued)

BASES

ACTIONS

G.1 (continued)

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.

H.1

Condition H applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function or one channel inoperable and no diverse channel OPERABLE.). Required Action H.1 requires restoring one channel in the Function(s) 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 two required channels inoperable in a Function or no diverse indicating channel OPERABLE is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel (diverse or primary) of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

Condition H is modified by two Notes. The first Note applies to the containment isolation valve position indication function and allows separate Condition entry for that function based on penetration flow paths. This note clarifies that Condition H may be applied to the containment isolation valve position indication function separately for each penetration flow path. The second Note is applicable to the second part of the Condition and clarifies that this part of the Condition applies only to those Functions that are not redundant and rely on diverse indication channels. Functions that rely on diverse indication are identified in Conditions C, D, E, and F.

(continued)

BASES

ACTIONS (continued)

I.1

If the Required Action and associated Completion Time of Conditions H are not met and Table 3.3.3-1 directs entry into Condition I, 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 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Condition I is modified by a Note that excludes the Containment Radiation and RVLIS Functions. These Functions are addressed by another Condition.

J.1

Alternate means of monitoring Reactor Vessel Water Level (RVLIS) and Containment Area Radiation are available. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.8, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas

(continued)

BASES

ACTIONS

J.1 (continued)

in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

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 unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, 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.

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

(continued)

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. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Safety Evaluation Report related to the operation of the Vogtle Electric Generating Plant, Units 1 and 2, NUREG-1137, Supplement No. 2, Section 7.5, May 1986.
2. Regulatory Guide 1.97, Rev. 2.
3. NUREG-0737, Supplement 1, "TMI Action Items."

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the operator with sufficient instrumentation and controls to place and maintain 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 (AFW) System and the steam generator (SG) safety valves or the SG atmospheric relief valves (ARVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW 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 establish control at the remote shutdown panel, and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the remote shutdown panel. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the remote shutdown control and 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).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Table B3.3.4-1.

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the SG safety valves or an SG ARV on at least one SG;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions.

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE. In some cases, Table B3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the Remote Shutdown System be placed in operation.

(continued)

BASES (continued)

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 control functions if control room instruments or controls become unavailable.

ACTIONS

A Remote Shutdown System division is inoperable when each function is not accomplished by at least one designated Remote Shutdown System channel that satisfies the OPERABILITY criteria for the channel's Function. These criteria are outlined in the LCO section of the Bases.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function. 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.

<u>A.1</u>

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes the control and transfer switches for any required function. A required Function is considered to be inoperable if one or more of its required channels is 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A 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 unit systems.

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 by the unit staff, 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System control circuit and transfer switch performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The surveillance may be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the scope or frequency of this SR requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

SR 3.3.4.3

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.

2. STI Evaluation 417332.

(continued)

BASES (continued)

TABLE B 3.3.4-1

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

	FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF CHANNELS
MONITORING INSTRUMENTATION		
1.	Source Range Neutron Flux	1
2.	Extended Range Neutron Flux	1
3.	RCS Cold Leg Temperature	1/loop
4.	RCS Hot Leg Temperature	2
5.	Core Exit Thermocouples	2
6.	RCS Wide Range Pressure	2
7.	Steam Generator Level Wide Range	1/loop
8.	Pressurizer Level	2
9.	RWST Level	1[(a)]
10.	BAST Level	1[(a)]
11.	CST Level	1/tank[(a)(c)]
12.	Auxiliary Feedwater Flow	1/loop
13.	Steam Generator Pressure	1/loop
TRANSFER AND CONTROL CIRCUITS		
1.	Reactivity Control	(b)
2.	RCS Pressure Control	(b)
3.	Decay Heat Removal	
	a. Auxiliary Feedwater	(b)
	b. Steam Generator Atmospheric Relief Valve[(d)]	(b)
4.	RCS Inventory/Charging System	(b)
5.	Safety support systems required for the above functions	(b)

(continued)

BASES

TABLE B 3.3.4-1 (continued)

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION AND CONTROLS

(a) Alternate local level indication may be established to fulfill the required number of channels.

(b) The required channels include the transfer switches and control circuits necessary to place and maintain the unit in a safe shutdown condition using safety grade components.

(c) Only required for the OPERABLE tank.

(d) Refer also to LCO 3.7.4.

B 3.3 INSTRUMENTATION

B 3.3.5 4.16 kV ESF Bus Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Each 4.16 kV ESF bus voltage is monitored by four channels of LOP instrumentation. The LOP instrumentation channels provide four separate signals from each bus to the associated sequencer. The LOP channel signals are generated by four potential transformers on each bus. Two transformers are connected between phases A and B and two transformers are connected between phases C and B. The signal from each transformer is converted in the sequencer cabinets to a 4-20 mA signal, and the resulting analog signal is fed to analog input modules and subsequently to comparator modules, functionally equivalent to 12 bistables also contained in the sequencer. Four bistables are set to trip on a loss of voltage signal (≥ 71.5% of bus voltage after a short time delay) and four bistables are set to trip on a degraded voltage signal (≥ 90% bus voltage for a longer period of time). Four additional bistables provide alarm functions and are not required operable by this Technical Specification. The LOP instrument channels lose their individual channel identity at the output of the bistables. The bistable output is combined in two-out-of-four logic circuitry for each trip function on each bus. The logic and actuation relays are integral to the sequencer circuitry and are required OPERABLE as part of the sequencer OPERABILITY requirements in LCOs 3.8.1 and 3.8.2 and the ESFAS actuation relay OPERABILITY requirements in LCO 3.3.2. The LOP channels are described in FSAR, Section 8.3 (Ref. 1).

The Loss of Voltage and Degraded Voltage instrument Functions provide signals to their respective sequencer to ensure an adequate ESF bus voltage is maintained and provide an anticipatory automatic start of the auxiliary feedwater pumps. A two-out-of-four logic combination for Loss of Voltage or Degraded Voltage on an ESF bus will initiate sequencer circuits to start the diesel generator, shed bus loads, and sequence loading of the diesel generator if required. The two-out-of-four logic on one ESF bus will also initiate sequencer circuits to start the motor-driven auxiliary feedwater pump associated with that bus. A two-out-of-four logic signal from both ESF buses will initiate sequencer circuitry to start the turbine-driven auxiliary feedwater pump.

(continued)

BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Trip Setpoints used in the bistables are based on the analytical limits used in the load flow calculations for each Unit. The selection of the Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The Allowable Values (AV) allow for deviation of the “as found” setting from the Nominal Trip Setpoint during testing, and serves as an operability limit for the purpose of the Channel Operational Test (COT). The magnitude of the AV is determined using specified allowances for rack calibration accuracy and rack drift.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the ESF Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESFAS.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 instrumentation, in conjunction with the ESF systems powered from the DGs, and the turbine-driven Auxiliary Feedwater Pump provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

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 short time delays used in conjunction with the loss of voltage and degraded voltage bistables are chosen to preclude sequence initiation due to momentary voltage fluctuations. The undervoltage sensing bistable time delays are nominal values and are not included in the safety analyses.

The LOP instrumentation channels satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The LCO for LOP instrumentation requires that four channels per bus of both the loss of voltage and degraded voltage Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the four 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 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 the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

(continued)

BASES (continued)

APPLICABILITY

The LOP 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.

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.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

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 in the LCO. 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 the LOP Function with only one loss of voltage and/or degraded voltage channel on one or both buses inoperable.

If one channel is inoperable, Required Action A.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP instrumentation channels are configured to provide a one-out-of-three logic to initiate a trip of the incoming offsite power.

A Note is added to allow bypassing an inoperable channel or the channel to be tested for up to 4 hours for surveillance testing of the remaining OPERABLE channels. This allowance is made where bypassing the channel does not cause an actuation and where at least two other channels are monitoring that parameter.

(continued)

BASES

ACTIONS

A.1 (continued)

The specified Completion Time and time allowed for bypassing one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

B.1

Condition B applies when more than one loss of voltage or more than one degraded voltage channel on a single bus is inoperable. Required Action B.1 requires restoring at least three channels to OPERABLE status.

Condition B provides the allowance for one or more functions with two or more channels inoperable on a single ESF bus. Once in this Condition the affected instrument function (loss of or degraded voltage) may no longer be single failure proof or may no longer be functional for the affected bus. In this case, operation in the Mode of applicability must be limited. Condition B allows 12 hours to restore the instrument function to the capability of continued operation in Condition A. The 12 hour allowance is based on the allowance for an inoperable sequencer (see electrical TS chapter). This time is appropriate because the affected instrument channels (loss of voltage or degraded voltage) are inputs to the sequencer and rely on sequencer circuits to perform their required actuations. The inoperability of these channels associated with a given ESF bus is no worse than the inoperability of a sequencer associated with that bus. Since the actuation logic and relays for the loss of power instruments (both AFW pump and diesel generator start) are an integral part of the sequencer, an inoperable sequencer may also prevent the loss of power instruments from performing their intended functions. Therefore, 12 hours provides a reasonable allowed outage time for these instruments that is consistent with the sequencer allowed outage time and that takes into account the low probability of an event occurring during this interval that would require the LOP instrumentation.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies when one or more functions with two or more channels are inoperable on both ESF buses. Once in this Condition the affected instrument function (loss of or degraded voltage) may no longer be single failure proof or may no longer be functional on both ESF buses. In this case, operation in the Mode of applicability must be limited. Condition C allows 1 hour to restore the instrument function to the capability of continued operation in Condition A or B. The 1 hour Completion Time provides a limited time to correct any errors or affect repairs and is appropriate for this Condition considering the low probability of an event occurring during this interval that would require a LOP function to actuate.

D.1 and D.2

Condition D applies to each of the LOP Functions when the Required Actions and associated Completion Times for Condition A, B, or C are not met when the unit is in MODE 1, 2, 3, or 4.

If the Required Actions and associated Completion Times of Condition A, B, or C are not met, then 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E applies to each of the LOP Functions when the Required Actions and associated Completion Times for condition A, B, or C are not met when the associated Diesel Generator is required OPERABLE by LCO 3.8.2.

In these circumstances the Conditions specified in LCO 3.8.2, "AC Sources — Shutdown," for the Diesel Generator made inoperable by failure of the LOP instrumentation are

(continued)

BASES

ACTIONS

E.1 (continued)

required to be entered immediately. The actions of this LCO provide for adequate compensatory actions to support unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel will perform the intended Function. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION. The Nominal Trip Setpoint considers factors that may affect channel performance such as rack drift, etc. Therefore, the Nominal Trip Setpoint (within the calibration tolerance) is the expected value for the CHANNEL CALIBRATION. However, the Allowable Value is the value that was used for the loss of voltage and degraded grid studies. Therefore, a channel with an actual Trip Setpoint value that is conservative with respect to the Allowable Value is considered OPERABLE; but the channel should be reset to the Nominal Trip Setpoint value (within the calibration tolerance) to allow for factors which may affect channel performance (such as rack drift) prior to the next surveillance.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay.

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. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology.

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

(continued)

BASES

ACTIONS

E.1 (continued)

required to be entered immediately. The actions of this LCO provide for adequate compensatory actions to support unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel will perform the intended Function. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION. The Nominal Trip Setpoint considers factors that may affect channel performance such as rack drift, etc. Therefore, the Nominal Trip Setpoint (within the calibration tolerance) is the expected value for the CHANNEL CALIBRATION. A channel with an actual Trip Setpoint value that is conservative with respect to the Allowable Value is considered OPERABLE; but the channel should be reset to the Nominal Trip Setpoint value (within the calibration tolerance) to allow for factors which may affect channel performance (such as rack drift) prior to the next surveillance.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay.

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. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology.

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

(continued)

BASES

REFERENCES

1. FSAR, Section 8.3.
2. FSAR, Chapter 15.
3. FSAR, Chapter 7.

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 Mini Purge System and the Shutdown Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Mini Purge System may be in use during reactor operation and the Shutdown Purge System will be in use with the reactor shutdown.

Containment ventilation isolation initiates on automatic safety injection (SI) signal or by manual actuation of Phase A Isolation. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss this mode of initiation.

Two radiation monitoring channels are required as input to the Containment Ventilation Isolation System. The containment purge exhaust monitors measure radiation in an air sample from the containment purge exhaust line. The purge exhaust radiation monitors consist of three different type detectors: gaseous, particulate, and iodine. The purge exhaust radiation detectors are treated as one channel which is considered OPERABLE if the particulate and iodine monitors are OPERABLE or the noble gas monitor is OPERABLE. In addition, two individual channels of containment area low range gamma monitors are provided. The two required radiation monitoring channels may be made up of any combination of the above described channels. Since the purge exhaust monitors constitute a sampling system, various components such as sample line valves, sample pumps, and filter motors are required to support monitor OPERABILITY.

Each of the purge systems has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from any one of the detectors initiates containment ventilation isolation, which closes both inner and outer containment isolation valves in the Mini Purge System and the Shutdown Purge System. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The safety analyses assume that the containment remains intact with penetrations unnecessary for core cooling isolated early in the event, within approximately 60 seconds. The isolation of the purge supply and exhaust valves has not been analyzed mechanistically in the dose calculations, although its rapid isolation is assumed. The containment purge supply and exhaust isolation radiation monitors act as backup to the SI signal to ensure closing of the purge supply and exhaust valves for events occurring in MODES 1 through 4. Manual isolation (using individual valve handswitches) following a radiation alarm is the assumed means for isolating containment in the event of a fuel handling accident during shutdown. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 (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

The LCO requires two channels OPERABLE. The operator can initiate Containment ventilation isolation at any time by using either of two switches in the control room (containment isolation Phase A switches). Either switch actuates both trains. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one CIA handswitch and the interconnecting wiring to the actuation logic cabinet.

(continued)

BASES

LCO (continued)

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two channels 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 ESFAS Function 1.b, SI. The applicable MODES and specified conditions for the Containment ventilation isolation portion of these Functions are different and less restrictive than those for their SI roles. If one or more of the SI Functions becomes inoperable in such a manner that only the Containment Ventilation Isolation Function is affected, the Conditions applicable to their SI Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Ventilation Isolation Functions specify sufficient compensatory measures for this case.

3. Containment Radiation

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment ventilation isolation remains OPERABLE. During CORE ALTERATIONS or movement of irradiated fuel assemblies in containment, the required channels provide input to control room alarms to ensure prompt operator action to manually close the containment purge and exhaust valves. It is also acceptable during CORE ALTERATIONS or movement of irradiated fuel to meet the requirements of this LCO by maintaining the radiation monitoring instrumentation necessary to initiate containment ventilation isolation OPERABLE, in accordance with the requirements stated for MODES 1, 2, 3, and 4 operability. The purge exhaust radiation detectors (RE-2565A, B&C) are treated as one channel which is considered OPERABLE if the particulate (RE-2565A) and iodine (RE-2565B) monitors are OPERABLE or the noble gas monitor (RE-2565C) is OPERABLE. In addition, two individual channels of containment area low range gamma monitors (RE-0002 & RE-0003) are provided. The two required radiation monitoring channels may be made up of any combination of the above described channels.

(continued)

BASES

LCO

3. Containment Radiation (continued)

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

(continued)

BASES

LCO (continued)

4. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements. The safety injection initiation function is applicable in MODES 1, 2, 3, and 4 only.

APPLICABILITY

The Manual Initiation, Automatic Actuation Logic and Actuation Relays, Containment Radiation, and Safety Injection Functions are required OPERABLE in MODES 1, 2, 3, and 4. 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.

During CORE ALTERATIONS or movement of irradiated fuel assemblies in containment, the air locks may be open provided they are isolable per LCO 3.9.4. Since the air locks can only be closed manually, it is assumed that containment ventilation isolation is accomplished by manually closing the purge and exhaust ventilation valves. Therefore, only OPERABLE radiation monitors are required to alert the operators of the need for containment ventilation isolation.

While in MODES 5 and 6 without fuel handling in progress, 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.

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 unit 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 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 3.3.6-1. The Completion Time(s) of

(continued)

BASES

ACTIONS (continued)

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 the failure of one required containment ventilation isolation radiation monitor channel. The failed channel must be restored to OPERABLE status. Four hours are allowed to restore the affected channel based on the low likelihood of events occurring during this interval, and recognition that one or more of the remaining channels will respond to most events.

B.1

Condition B applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for these Functions. It also addresses the failure of multiple 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 a manual or automatic actuation channel is inoperable, no radiation monitoring channels operable, or the Required Action and associated Completion Time of Condition A are 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.

A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

C.1 and C.2

Condition C addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Required Action A.1. If no radiation monitoring channels are operable or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain containment purge supply and exhaust isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.4, "Containment Penetrations," are met for each penetration not in the required status. The Completion Time for these Required Actions is Immediately.

A Note states that Condition C is applicable during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

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 by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

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 pulse 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. For MODES 1, 2, 3, and 4, this test verifies the capability of the instrumentation to provide the containment purge and exhaust system isolation. During CORE ALTERATIONS and movement of irradiated fuel in containment, this test verifies the capability of the required channels to generate the signals required for input to the control room alarm. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology.

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.

For slave relays and associated auxiliary relays in the CVI actuation system circuit that are Potter and Brumfield (P&B) type Motor Driven Relays (MDR), the SLAVE RELAY TEST is performed on an 18-month frequency. This test frequency is based on relay reliability assessments presented in WCAP-13878, "Reliability Assessment of Potter and Brumfield MDR Series Relays." The reliability assessments are relay specific and apply only to Potter and Brumfield MDR series relays. Quarterly testing of the slave relays associated with non-P&B MDR auxiliary relays will be administratively controlled until an alternate method of testing the auxiliary relays is developed or until they are replaced by P&B MDR series relays.

SR 3.3.6.6

SR 3.3.6.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. 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.).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.6 (continued)

The test also includes trip devices that provide actuation signals directly to the SSPS, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.7

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. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology.

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

SR 3.3.6.8

This SR ensures the individual channel 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 FSAR. Individual component response times are not modeled in the analyses. The analyses model the overall or elapsed time, from the point at which the parameter exceeds the Trip Setpoint Valve at the sensor, to the point at which the equipment in both trains reaches the required functional state.

RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

(continued)

BASES

REFERENCES	1. 10 CFR 100.11.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

BASES

BACKGROUND

The CREFS provides a pressurized control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the normal Control Room Ventilation System provides control room ventilation. Upon receipt of an actuation signal, the CREFS initiates filtered ventilation and pressurization of the control room. The CREFS consists of four 100% capacity ventilation/filtration system trains, configured two per unit. The units share a common control room, with two outside air intakes. The intakes are connected to a common air inlet header to which the four trains of CREFS are connected. Each air intake is equipped with two redundant radiogas monitors. Each monitor actuates both trains of CREFS in the associated unit. Each CREFS train will also start on a Safety Injection (SI) signal from the associated unit. The SI function is discussed in LCO 3.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation." In addition, each CREFS train has a system level manual initiation that functions the same as the automatic action for a CREFS train, and each CREFS train may also be started and aligned using component level manual controls.

The system is equipped with a lead/lag logic designed to control the operation of the CREFS in such a manner so as to preclude extended simultaneous operation of more than two CREFS trains. Limiting the CREFS to two train operation ensures that the system will function within the limitations established by the control room dose analysis (Ref. 1). The lead/lag logic is designed to start the train B CREFS (lead train) immediately upon receipt of an auto start signal. Should the train B CREFS fail to start and/or establish discharge flow within approximately 10 seconds after receipt of an auto start signal, the train A CREFS (lag train) will start. This system is described in more detail in the Bases for LCO 3.7.10, "Control Room Emergency Filtration System."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CREFS 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 CREFS is a backup for the SI signal actuation. This ensures initiation of the CREFS during a loss of coolant accident.

The radiation monitor actuation of the CREFS during movement of irradiated fuel assemblies and CORE ALTERATIONS is the primary means to ensure control room habitability in the event of a fuel handling accident.

The CREFS Actuation Instrumentation satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREFS is OPERABLE.

1. <u>Manual Initiation</u>

The LCO requires one channel OPERABLE. The operator can initiate the CREFS 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.

Since manual initiation is not a credited Function, only one manual initiation channel for both units is required OPERABLE.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet.

(continued)

BASES

LCO (continued)

2. Automatic Actuation Logic and Actuation Relays

The LCO requires four trains of Actuation Logic and Relays OPERABLE (two per unit) 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 ESFAS Function 1.b., SI, in LCO 3.3.2. The applicable MODES and specified conditions for the CREFS portion of these functions are different and less restrictive than those specified for their SI roles. If one or more of the SI functions becomes inoperable in such a manner that only the CREFS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the CREFS Functions specify sufficient compensatory measures for this case.

3. Control Room Radiation

The LCO specifies four (two per unit) required Control Room Air Intake Radiation Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CREFS remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

4. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements. The safety injection initiation function is applicable in MODES 1, 2, 3, and 4 only.

(continued)

BASES (continued)

APPLICABILITY

The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, and during CORE ALTERATIONS and movement of irradiated fuel assemblies.

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 unit 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 Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. 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.

The following ACTIONS have been developed to take credit for the redundancy and inherent flexibility designed into the four 100% capacity CREFS trains. These ACTIONS were reviewed to ensure that the system function would be maintained under accident conditions coupled with a postulated single failure. The results of this review are documented in Reference 2.

A.1

Condition A is applicable when the single required manual initiation channel becomes inoperable. In this condition there is no system level manual initiation of a CREFS train available. The Actions require that the channel be restored to OPERABLE status in 7 days. The lack of system level manual initiation capability does not preclude automatic initiation by the redundant automatic actuation channels. The SI-A and SI-B signals and redundant radiation monitor

(continued)

BASES

ACTIONS

A.1 (continued)

channels for each unit are adequate to perform the control room protection function. In addition, component level manual initiation of each CREFS train is available to the control room operators. The 7 day Completion Time is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

B.1

If the Required Action of Condition A, to restore the inoperable manual initiation channel to OPERABLE status, is not completed in 7 days, action must be taken to place the plant in a condition where the manual initiation function is no longer necessary. Action B.1 requires that one CREFS train be placed in the emergency mode of operation within 6 hours. This action accomplishes the manual function for a CREFS train. This action also ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The Completion Time of 6 hours is reasonable to initiate the CREFS train considering the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

C.1

Condition C is applicable when a single automatic actuation logic and relay channel becomes inoperable. The Actions require that the channel be restored to OPERABLE status in 7 days. In this condition, there is one completely redundant automatic actuation and relay channel still OPERABLE in the affected unit. The remaining OPERABLE channel is adequate to perform the control room protection function. In addition, system level manual initiation of each CREFS train is available to the control room operators. However, the overall reliability of the actuation

(continued)

BASES

ACTIONS

C.1 (continued)

instrumentation is reduced and operation in this condition is limited. The 7 day Completion Time is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

D.1

If the Required Action of Condition C, to restore the inoperable automatic actuation logic and relay channel to OPERABLE status, is not completed in 7 days, action must be taken to place the plant in a condition where the inoperable automatic actuation channel is no longer necessary. Action D.1 requires that one CREFS train in the unaffected unit be placed in the emergency mode of operation within 6 hours. This action compensates for the inoperable automatic actuation channel. This action also ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The Completion Time of 6 hours is reasonable to initiate the CREFS train considering the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

E.1

Condition E is applicable when one automatic actuation logic and relay channel becomes inoperable in each unit. The Actions require that both channels be restored to OPERABLE status in 7 days. In this condition, there is one completely redundant automatic actuation and relay channel still OPERABLE in each unit. The remaining OPERABLE channel in each unit is adequate to perform the control room protection function. In addition, system level manual initiation of each CREFS train is available to the control room operators. However, the overall reliability of the actuation instrumentation is reduced and operation in this

(continued)

BASES

ACTIONS

E.1 (continued)

condition is limited. The 7 day Completion Time is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

F.1

If the Required Action of Condition E, to restore both inoperable automatic actuation logic and relay channels to OPERABLE status, is not completed in 7 days, action must be taken to place the plant in a condition where the inoperable automatic actuation channels are no longer necessary. Action F.1 requires that one CREFS train in each unit be placed in the emergency mode of operation within 6 hours. This action compensates for the inoperable automatic actuation channels. This action also ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The Completion Time of 6 hours is reasonable to initiate the CREFS trains considering the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

G.1 and G.2

Condition G is applicable when two automatic actuation logic and relay channels become inoperable in one unit. Required Actions G.1 and G.2 provide equivalent compensatory actions for this condition. G.1 requires that two CREFS trains in the unaffected unit be placed in the emergency mode of operation within 1 hour. G.2 requires one CREFS train in each unit be placed in the emergency mode of operation within 1 hour. In this condition, there is no CREFS automatic actuation channel available in the affected unit. Required Action G.1 or G.2 will compensate for the inoperable automatic actuation channels and ensure the control room remains protected for all postulated accident

(continued)

ACTIONS

G.1 and G.2 (continued)

and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The 1 hour Completion Time reflects the urgency with which this condition must be addressed and is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation.

H.1

Condition H is applicable when three automatic actuation logic and relay channels become inoperable. Action H.1 requires that two CREFS trains in the unit with one inoperable channel be placed in the emergency mode of operation within 1 hour. In this condition, there is no CREFS automatic actuation channel available in one unit and only one OPERABLE automatic actuation channel in the other unit. Required Action H.1 provides adequate compensatory measures for the inoperable automatic actuation channels and ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The 1 hour Completion Time reflects the urgency with which this condition must be addressed and is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation.

I.1

Condition I is applicable when four automatic actuation logic and relay channels become inoperable. Action I.1 requires that two CREFS trains be placed in the emergency mode of operation within 1 hour. In this condition, there are no CREFS automatic actuation channels available in either unit. Since no automatic actuations are possible, there are no preferred CREFS trains to place in emergency mode of operation. Required Action I.1 provides adequate compensatory measures for the inoperable automatic actuation

(continued)

BASES

ACTIONS

I.1 (continued)

channels and ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The 1 hour Completion Time reflects the urgency with which this condition must be addressed and is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation.

J.1

Condition J is applicable when a single air intake radiogas monitor channel becomes inoperable. The Action requires that the channel be restored to OPERABLE status in 7 days. In this condition, there is one completely redundant air intake radiogas monitor channel still OPERABLE in the affected unit. The remaining OPERABLE radiogas monitor channel will initiate both automatic actuation logic and relay channels which will start both trains of CREFS in that unit. In addition, system level manual initiation of each CREFS train is available to the control room operators. However, the overall reliability of the actuation instrumentation is reduced and operation in this condition is limited. The 7 day Completion Time is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

K.1

If the Required Action of Condition J, to restore the inoperable air intake radiogas monitor channel to OPERABLE status, is not completed in 7 days, action must be taken to place the plant in a condition where the inoperable radiogas monitor channel is no longer necessary. Required Actions K.1 and K.2 provide equivalent compensatory actions for this condition. Action K.1 requires that air intake damper associated with the inoperable radiogas monitor be locked closed and the damper associated with the unaffected outside

(continued)

BASES

ACTIONS

K.1 (continued)

air intake be locked open. Action K.1 ensures all air intake is monitored by redundant radiogas monitors. Action K.2 requires one train of CREFS be placed in the emergency mode of operation which accomplishes the radiogas monitor channel function. Either of these actions ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The Completion Time of 6 hours is reasonable to lock the outside air intake dampers in the required position or initiate a CREFS train considering the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

L.1

Condition L is applicable when an air intake radiogas monitor channel becomes inoperable in each unit. The Action requires that both channels be restored to OPERABLE status in 7 days. In this condition, there is one completely redundant air intake radiogas monitor channel still OPERABLE in each unit. The remaining OPERABLE radiogas monitor channel will initiate both automatic actuation logic and relay channels which will start both trains of CREFS for the associated unit. In addition, system level manual initiation of each CREFS train is available to the control room operators. However, the overall reliability of the actuation instrumentation is reduced and operation in this condition is limited. The 7 day Completion Time is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

M.1

If the Required Action of Condition L, to restore both inoperable air intake radiogas monitor channels to OPERABLE

(continued)

BASES

ACTIONS

M.1 (continued)

status, is not complete in 7 days, action must be taken to place the plant in a condition where the inoperable radiogas monitor channels are no longer necessary. Action M.1 requires that one CREFS train be placed in the emergency mode of operation within 6 hours. This action compensates for the inoperable radiogas monitor channels. This action also ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The Completion Time of 6 hours is reasonable to initiate the CREFS train considering the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

N.1 and N.2

Condition N is applicable when two air intake radiogas monitor channels are inoperable in one unit. In this condition, one air intake is without radiation monitoring capability and the other air intake retains fully operable and redundant radiogas monitoring capability. Actions N.1 and N.2 provide equivalent compensatory actions for this condition. Action N.1 requires that the outside air intake damper in the affected unit be locked closed and the damper in the unaffected unit air intake be locked open within 1 hour. Action N.2 requires that a CREFS train in each unit be placed in the emergency mode of operation within 1 hour. Action N.1 ensures all air intake is monitored by redundant radiogas monitors. Action N.2 accomplishes the radiogas monitor channel function by placing two CREFS trains in operation. Either of these actions ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished. The 1 hour Completion Time reflects the urgency with which this condition must be addressed and is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation.

(continued)

BASES

ACTIONS (continued)

O.1, O.2.1, O.2.2.1, and O.2.2.2

Condition O is applicable when three air intake radiogas monitor channels are inoperable. In this condition, one air intake is without radiation monitoring capability and the other air intake is monitored by a single radiogas monitor channel. Action O.1 and the set of O.2 actions provide equivalent compensatory actions for this condition. Action O.1 requires that a CREFS train in each unit be placed in the emergency mode of operation within 1 hour. Action O.1 accomplishes the radiogas monitor channel function and ensures the control room is protected for all postulated accident and single failure considerations by placing two CREFS trains in operation. As an alternative to action O.1, the O.2 set of actions may be performed. Action O.2.1 requires that the outside air intake damper in the unit with two inoperable channels be locked closed and the damper in the other unit's air intake be locked open within 1 hour. In this condition all air flow into the control room is monitored by the single OPERABLE radiogas monitoring channel. The remaining OPERABLE radiogas monitor channel will initiate both automatic actuation logic and relay channels which will start both trains of CREFS in the associated unit. In addition, system level manual initiation of each CREFS train is available to the control room operators. However, the overall reliability of the actuation instrumentation is reduced and operation in this condition is limited. Action O.2.2.1 requires the single inoperable channel in the air intake that is locked open be restored to OPERABLE status in 7 days. Completion of action O.2.2.1 will restore redundant radiogas monitoring capability to the only air intake in service. As an alternative to action O.2.2.1, action O.2.2.2 requires that one CREFS train be placed in the emergency mode. Action O.2.2.2 provides adequate compensatory action in the event the single inoperable radiogas monitor channel in the locked open air intake is not restored to OPERABLE status. Completion of action O.2.2.1 or O.2.2.2 ensures the control room remains protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the control room, limit the radiation dose, and provide adequate cooling remains undiminished.

(continued)

BASES

ACTIONS

O.1, O.2.1, O.2.2.1, and O.2.2.2 (continued)

The 1 hour Completion Time for actions O.1 and O.2.1 reflects the urgency with which this condition must be addressed and is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation. The 7 day Completion Time of actions O.2.2.1 and O.2.2.2 is reasonable based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining CREFS manual and automatic actuation instrumentation.

P.1

Condition P is applicable when four air intake radiogas monitor channels are inoperable. In this condition, the air flow into the control room is not monitored. Action P.1 requires that a CREFS train in each unit be placed in the emergency mode of operation within 1 hour. Action P.1 accomplishes the radiogas monitor channel function and ensures the control room is protected for all postulated accident and single failure considerations by placing the two CREFS trains in operation. The 1 hour Completion Time for action P.1 reflects the urgency with which this condition must be addressed and is a reasonable time to initiate two CREFS trains considering the low probability of an event occurring during this time interval that would require CREFS operation.

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 CREFS Actuation Functions.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

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 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 3.3.7.2

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 CREFS actuation. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3

SR 3.3.7.3 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 pulse 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 Frequency is justified in WCAP-10271-P-A, Supplement 2, Rev. 1 (Ref. 1).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.4

SR 3.3.7.4 is the performance of a TADOT. This test is a check of the Manual Actuation Functions. Each Manual Actuation Function is tested, which in some instances 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 tested have no setpoints associated with them.

SR 3.3.7.5

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.

There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology.

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

SR 3.3.7.6

This SR ensures the individual channel ESF RESPONSE TIME for the CREFS radiogas monitor actuation instrumentation is less than or equal to the maximum values assumed in the accident analyses. Response time testing acceptance criteria are included in the FSAR, Chapter 7 (Ref. 3). 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 in both trains 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.6 (continued)

be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the constants set to their nominal values 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.

ESF RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

REFERENCES

1. Westinghouse to SCS Letter 88GP-G-0025, dated May 23, 1988. Transmittal of PMTC FSAR changes.

2. VEGP Calculation No. X6CNA.09.01, Control Room HVAC Technical Specifications, 21 October 1988.

3. FSAR, Chapter 7.

B 3.3 INSTRUMENTATION

B 3.3.8 High Flux at Shutdown Alarm (HFASA)

BASES

BACKGROUND

The primary purpose of the HFASA is to warn the operator of an unplanned boron dilution event in sufficient time (15 minutes prior to loss of shutdown margin) to allow manual action to terminate the event. The HFASA is used for this purpose in MODES 3 and 4, and MODE 5 with the loops filled.

The HFASA consists of two channels of alarms, with each channel receiving input from one source range channel. An alarm setpoint of ≤2.3 times background provides at least 15 minutes from the time the HFASA occurs to the total loss of shutdown margin due to an unplanned dilution event. This meets the Standard Review Plan criteria for mitigating the consequences of an unplanned dilution event by relying on operator action.

APPLICABLE SAFETY ANALYSES

The analysis presented in Reference 1 identifies credible boron dilution initiators. Time intervals from the HFASA until loss of shutdown margin were calculated. The results demonstrate that sufficient time for operator response is available to terminate an inadvertent dilution event taking credit for one HFASA with a setpoint of ≤2.3 times background.

The HFASA satisfied Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The LCO requires two channels of HFASA to be OPERABLE with input from two source range channels to provide protection against single failure.

APPLICABILITY

The HFASA must be OPERABLE in MODES 3, 4, and 5.

The Applicability is modified by a Note which allows the HFASA to be blocked in MODE 3 during reactor startup so that spurious alarms are not generated.

(continued)

BASES

APPLICABILITY (continued)

In MODES 1 and 2, operators are alerted to an unplanned dilution event by a reactor trip on overtemperature delta-T or power range neutron flux high, low setpoint, respectively. As a protective measure in addition to HFASA, in MODE 5 with the loops not filled, unplanned dilution events are precluded by requiring the unborated water source (reactor makeup water storage tank (RMWST)) to be isolated.

ACTIONS

A.1

With one channel of HFASA inoperable, Required Action A.1 requires the inoperable channel to be restored within 48 hours. In this condition, one channel of HFASA remains available to provide protection. The 48 hour Completion Time is consistent with that required for an inoperable source range channel. Required Action A.1 is modified by a Note stating that LCO 3.0.4c is applicable provided that Required Actions B.1 and B.2 are met. When Condition A (and Required Action A.1) are applicable, the Note permits MODE changes provided that Required Action B.1 and B.2 are met. Required Action B.1 is a periodic verification of shutdown margin, and Required Action B.2 ensures that the unborated water source isolation valves are shut, precluding a boron dilution event. With one channel of HFASA inoperable, it is prudent to take the compensatory actions of Required Actions B.1 and B.2 if MODE changes are desired or required.

B.1 and B.2

With the Required Action A.1 and associated Completion Time not met, or with both channels of HFASA inoperable, the appropriate ACTIONS are to verify that the required SDM is present and isolate the unborated water source by performing

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

SR 3.9.2.1. This places the unit in a condition that precludes an unplanned dilution event. The Completion Times of 1 hour and once per 12 hours thereafter for verifying SDM provide timely assurance that no unintended dilution occurred while the HFASA was inoperable and that SDM is maintained. The Completion Times of 4 hours and once per 14 days thereafter for verifying that the unborated source is isolated provide timely assurance that an unplanned dilution event cannot occur while the HFASA is inoperable and that this protection is maintained until the HFASA is restored.

SURVEILLANCE REQUIREMENTS

The HFASA channels are subject to a COT and a CHANNEL CALIBRATION.

SR 3.3.8.1

SR 3.3.8.1 requires the performance of a COT to ensure that each channel of the HFASA and its setpoint are OPERABLE. This test shall include verification that the HFASA setpoint is less than or equal to 2.3 times background. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This Surveillance Requirement is modified by a Note that provides a 4-hour delay in the requirement to perform this surveillance for the HFASA instrumentation upon entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without delay for the performance of the surveillance to meet the applicability requirements in MODE 3.

SR 3.3.8.2

SR 3.3.8.2 requires the performance of a CHANNEL CALIBRATION. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found setting are consistent with those established by the setpoint methodology. This test verifies that each channel responds to a measured parameter within the necessary range and accuracy. It encompasses the HFASA portion of the instrument loop. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Subsection 15.4.6.

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 DNB design criterion will be met for each of the transients analyzed.

The design method employed to meet the DNB design criterion for the VANTAGE 5 and LOPAR fuel assemblies is the Revised Thermal Design Procedure (RTDP). With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined in order to meet the DNB design criterion.

The RTDP design limit DNBR values are 1.24 and 1.23 for the typical and thimble cells, respectively, for the VANTAGE 5 fuel analyses with the WRB-2 correlation. For the LOPAR fuel analyses, the RTDP design limit DNBR values are 1.23 and 1.22 for the typical and thimble cells, respectively.

Additional DNBR margin is maintained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. This margin between the design and safety analysis limit DNBR values is used to offset known DNBR penalties (e.g., rod bow and transition core) and to provide DNBR margin for operating and design flexibility.

The Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. In the STDP method the parameters used in analysis are treated in a conservative way from a DNBR standpoint. The parameter uncertainties are applied directly to the safety analyses input values to give the lowest minimum DNBR. The design

(continued)

BASES

BACKGROUND (continued)

limit DNBR for STDP is the 95/95 limit for the appropriate DNB correlation. Again, additional DNBR margin is maintained in the safety analyses to offset the applicable DNBR penalties.

For both the WRB-1 and the WRB-2 correlations, the 95/95 DNBR correlation limit is 1.17. The W-3 DNB correlation is used for both fuel types where the primary DNBR correlations are not applicable. The WRB-1 and WRB-2 correlations were developed based on mixing vane data and therefore are only applicable in the heated rod spans above the first mixing vane grid. The W-3 correlation, which does not take credit for mixing vane grids, is used to calculate DNBR values in the heated region below the first mixing vane grid. In addition, the W-3 correlation is applied in the analysis of accident conditions where the system pressure is below the range of the primary correlations. For system pressures in the range of 500 to 1000 psia, the W-3 correlation limit is 1.45. For system pressures greater than 1000 psia, the W-3 correlation limit is 1.30.

The RCS pressure and average temperature limits are consistent with operation within the nominal operational envelope. A lower pressure and/or higher average temperature will cause the reactor 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. 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.

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 DNB design criterion. Changes to the unit that could impact these parameters must be assessed for their impact on the DNB design criterion. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	transients analyzed 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)." The pressurizer pressure limit of 2199 psig and the RCS average temperature limit of 592.5°F correspond to analytical limits of 2185 psig and 594.4°F used in the safety analyses, with allowance for measurement uncertainty. The indicated RCS flow value of 384,509 gpm corresponds to an analytical value of 374,400 gpm with allowance for measurement and indication uncertainties. The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
LCO	This LCO specifies limits on the monitored process variables — pressurizer pressure (PI-0455A,B&C, PI-0456 & PI-0456A, PI-0457 & PI-0457A, and PI-0458 & PI-0458A), RCS average temperature (TI-0412, TI-0422, TI-0432, and TI-0442), and RCS total flow rate (FI-0414, FI-0415, FI-0416, FI-0424, FI-0425, FI-0426, FI-0434, FI-0435, FI-0436, FI-0444, FI-0445, FI-0446) — to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNB design criterion in the event of a DNB limited transient. RCS total flow rate contains a measurement error of 2.7% based on performing a precision heat balance above 90% RTP and using the result to calibrate the RCS flow rate indicators. This measurement uncertainty includes a 0.1% penalty to account for potential fouling of the feedwater venturi, which might not be detected and could bias the result from the precision heat balance in a nonconservative manner. Any fouling that might bias the flow rate measurement greater than 0.1% can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and

(continued)

BASES

LCO (continued)

compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNB design criterion 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.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp > 5% RTP per minute or a THERMAL POWER step > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action.

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 flow rate exhibits degradation and the actual total RCS flow rate is below the LCO limit as determined by precision heat balance, power must be reduced, as required by Required Action C.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

(continued)

BASES

ACTIONS

A.1 (continued)

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

B.1

If degradation in RCS total flow rate is detected via the flow rate indicators, a precision calorimetric heat balance must be performed within 7 days of detection of the degradation. The precision heat balance will positively verify actual RCS total flow rate. The 7-day Completion Time is adequate to allow for the setup necessary for this measurement and is acceptable since the RCS low flow reactor trips will protect the reactor against actual low flow conditions.

C.1

If Required Actions A.1 or B.1 are not met 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 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 plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

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

(continued)

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 RCS flow instrumentation indicates from 0% to 120% as opposed to actual flow in gallons per minute. Therefore, the flow instrumentation is used to detect degradation in flow rather than as a comparison against the actual limit in gallons per minute. Degradation is defined as a change in indicated percent flow which is greater than the instrument channel inaccuracies and parallax errors. 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 correlated with the precision flow measurement and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate. In addition, in order to ensure that the measurement uncertainty assumed in the limit for RCS total flow rate is maintained, the instrumentation used for the precision calorimetric heat balance will be calibrated within 30 days prior to the precision calorimetric.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.4 (continued)

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 plant 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.

REFERENCES

1. FSAR, 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 plant 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.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 ≥ the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant 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. 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,

(continued)

BASES

APPLICABILITY (continued)

it is necessary to allow RCS loop average temperatures to fall below the HZP temperature, 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 plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be periodically verified at or above 551°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 4.3 and Subsections 15.0.3 and 15.4.8.

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.

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 mainly to the vessel. The limits do not apply to the pressurizer or to the pressurizer surge line, which have different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 1 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 XI, Appendix G (Ref. 2).

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.

(continued)

BASES

BACKGROUND (continued)

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. 3) and Appendix H of 10 CFR 50 (Ref. 4). 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. 5).

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.

The criticality limit curve includes the Reference 1 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."

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. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

(continued)

BASES (continued)

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 7 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 and the pressurizer surge line. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

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;

(continued)

BASES

LCO (continued)

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. 1). 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 limits do not apply to the pressurizer or the pressurizer surge line.

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 and 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 evaluation is required to determine if RCS operation can continue. The

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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.

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 plant 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 cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig 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.

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.

ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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.

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. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.

(continued)

BASES

REFERENCES (continued)

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. WCAP-14040-A, Revision 4.

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.

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.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

All of the accident/safety analyses performed at full rated thermal power assume that all four RCS loops are in operation as an initial condition. Some accident/safety analyses have been performed at zero power conditions assuming only two RCS loops are in operation to conservatively bound lower modes of operation. The events which assume only two RCPs in operation include the uncontrolled RCCA (Bank) withdrawal from subcritical and the rod ejection events. While all accident/safety analyses performed at full rate thermal power assume that all the RCS loops are in operation, selected events examine the effects resulting from a loss of RCP operation. These include the complete and partial loss of forced RCS flow, reactor coolant pump rotor seizure, and reactor coolant pump shaft break events. For each of these events, it is demonstrated that all the applicable safety criteria are satisfied. For the remaining accident/safety analyses, operation of all four RCS loops during the transient up to the time of reactor trip is assumed thereby ensuring that all the applicable acceptance criteria are satisfied. Those transients analyzed beyond the time of reactor trip were examined assuming that a loss of offsite power occurs which results in the RCPs coasting down.

By ensuring that the plant operates with all RCS loops in operation in MODES 1 and 2, 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.

(continued)

BASES (continued)

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 plant 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.

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 help ensure that forced flow is providing heat removal while maintaining the margin to DNB.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.4.1 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Chapter 15.

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. The 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 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. 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.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 must be in operation. Two RCS loops are required to be in operation in MODE 3 with the Rod Control System capable of rod withdrawal 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 ensure adequate decay heat removal capability.

The Note permits all RCPs to be de-energized 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

(continued)

BASES

LCO (continued)

change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test 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.

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).

(continued)

BASES (continued)

ACTIONS

A.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.

B.1

If restoration is not possible within 72 hours, 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 plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If the required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal (e.g., de-energize 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 Times of 1 hour to restore the required RCS loop to operation or 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.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, place the Rod Control System in a condition incapable of rod withdrawal (e.g., all CRDMs must be de-energized 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 and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets 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 OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which help 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 SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side water level (LI-0501, LI-0502, LI-0503, LI-0504) for the required RCS loops is above the highest point of the steam generator U-tubes for each required loop. To assure that the steam generator is capable of functioning as a heat sink for the removal of decay heat, the U-tubes must be completely submerged. Plant procedures provide the minimum indicated levels for the range of the steam generator operating conditions required to satisfy this SR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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

REFERENCES

None.

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.

The reactor coolant is circulated through 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, either RCPs or RHR loops can be used 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, RCS circulation is considered in the determination of 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).

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

(continued)

BASES

LCO (continued)

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 or RHR pumps to be de-energized 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. These tests are initially performed during startup testing. However, 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 necessary testing, 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 initial startup test 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 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 any time during MODE 4 operation with any RCS cold leg temperature ≤ the Cold Overpressure Protection System (COPS) arming temperature specified in the PTLR. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started. The Note further restricts starting an RCP to a range of temperature differentials between the SGs and the RCS that is consistent with analysis assumptions used to demonstrate that the RHR design pressure is not exceeded when the RHR suction isolation valves are open.

(continued)

BASES

LCO (continued)

An OPERABLE RCS loop is comprised of an OPERABLE RCP and an OPERABLE SG which has the minimum water level specified in SR 3.4.6.2, and the necessary aspects of the Auxiliary Feedwater and Condensate Storage Tank Systems available to provide feedwater. Additionally, the OPERABILITY of an SG must include a means by which the decay heat may be removed (i.e., the capability of the atmospheric relief valve to stroke or the condenser is available).

Similarly for the RHR System, an OPERABLE RHR loop comprises 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 meet single failure considerations.

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).

ACTIONS

A.1

If one required RCS loop is inoperable and two RHR loops are inoperable, 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.

(continued)

BASES

ACTIONS (continued)

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, 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, 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 or in operation, except during conditions permitted by Note 1 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 OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that one RCS or RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side water level (LI-0501, LI-0502, LI-0503, LI-0504) for the required RCS loops is above the highest point of the steam generator U-tubes for each required loop. To assure that the steam generator is capable of functioning as a heat sink for the removal of decay heat, the U-tubes must be completely submerged. Plant procedures provide the minimum indicated levels for the range of the steam generator operating conditions required to satisfy this SR. 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 pump 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 noncondensable 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.4 (continued)

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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

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 RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note 1 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.4 (continued)

This SR is modified by a Note 2 clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

None.

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 the transfer of this heat either to the steam generator (SG) secondary side coolant or 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 are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, 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 LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels above the highest point of the SG U-tubes to provide an alternate method for decay heat removal. To assure that the SG is capable of functioning as a heat sink

(continued)

BASES

BACKGROUND (continued)

for the removal of decay heat, the U-tubes must be completely submerged, which is achieved if the SG level criteria are satisfied.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

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 above the highest point of the SG U-tubes. 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 above the highest point of the SG U-tubes. Should the operating RHR loop fail, the SGs could be used to remove the decay heat. SG wide (LI 501-504) and SG narrow (LI 517-519, LI 527-529, LI 537-539, LI 547-549, and LI 551-554) range instrumentation are available for determining SG water level.

Note 1 permits all RHR pumps to be de-energized ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. These tests are initially performed during startup testing. However, 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 necessary testing, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

(continued)

BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test 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 up to 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 during the only time 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) during MODE 5 with the RCS loops filled. 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.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. A SG can perform as a heat sink when it has an adequate water level and is OPERABLE. Management of gas voids is important to RHR System OPERABILITY. Additional requirements for an SG to be available as a heat sink are:

a. RCS loops and reactor pressure vessel filling and venting complete; and

(continued)

BASES

LCO (continued)

b. RCS pressure maintained > 100 psig since the most recent filling and venting.

The loops are not considered to be filled if these requirements are not satisfied.

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 above the highest point of the SG U-tubes.

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 one RHR loop is inoperable and the required SGs have secondary side water levels below the highest point of the SG U-tubes, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to

(continued)

BASES

ACTIONS

B.1 and B. 2 (continued)

OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help 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 above the highest point of the SG U-tubes ensures an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. To assure that the SG is capable of functioning as a heat sink for the removal of decay heat, the U-tubes must be completely submerged, which is achieved if the SG level criteria are satisfied. Plant procedures provide the minimum indicated levels for the range of the SG operating conditions required to satisfy this SR. If both RHR loops are OPERABLE, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.3

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.3 (continued)

Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondaryside water level is above the highest point of the SG U-tubes 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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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. Operating procedures direct the implementing actions to meet this surveillance requirement and ensure the system is sufficiently filled with water.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.4 (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 subset 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 RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

None.

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.

The specified condition of Applicability "Loops not filled" is defined as when RCS pressure is not maintained >100 psig since the most recent filling and venting. It is in this specified condition of Applicability, where the smallest active volume for the RCS can occur during midloop operation. Based on the smallest active volume considered for the boron dilution transient, it was determined that each valve used to isolate unborated water sources shall be secured closed in MODE 5 with the RCS loops not filled. At least one valve in each flowpath from the Reactor Makeup Water Storage Tank (RMWST) to the suction of each charging pump shall be closed and secured in position. The applicable valve(s) will be controlled by plant procedures, which will ensure proper valve position. This action effectively isolates the unborated water source of the chemical and volume control system (CVCS) from the RCS, thereby precluding an uncontrolled boron dilution event in MODE 5 with the RCS loops not filled. However, the maximum possible flow rate from the RMWST, through the chemical mixing tank, to the suction of the charging pumps is sufficiently small that the applicable valve(s) can be allowed open under administrative control provided the applicable shutdown margin requirements of LCO 3.1.1 are met and the high flux at shutdown alarm is

(continued)

BASES

BACKGROUND (continued)

OPERABLE. Opening the applicable valve(s) is necessary to facilitate chemistry control of the RCS (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing. The active volume of the RCS is also considered in the analysis of malfunctions of the chemical and volume control system (CVCS) that could result in a decrease in the boron concentration of the RCS.

RCS loops in MODE 5 (loops not filled) satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

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 de-energized for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained greater than 10°F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

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 during the only time when these tests are safe and possible.

(continued)

BASES

LCO (continued)

Note 3 allows valves in the flowpath from the RMWST, through the chemical mixing tank, to the suction of the charging pumps to be open under administrative control provided the SDM requirements of LCO 3.1.1 are met and the high flux at shutdown alarm is OPERABLE. (OPERABILITY of the high flux at shutdown alarm is defined by LCO 3.3.8.) This permits the addition of chemicals to the RCS as necessary in this MODE of operation while minimizing the risk of an uncontrolled boron dilution transient.

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.

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

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, 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 and operation. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

C.1

If the valve(s) required to be closed are discovered to be open (except as provided by Note 3 to the LCO), action must be initiated immediately to secure the open valve(s) in the closed position in order to preclude an uncontrolled boron dilution transient.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification that one loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help 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 the required number of pumps are OPERABLE ensures that additional pumps 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.8.3

Verification that the required valve(s) are closed (except as provided in Note 3 to the LCO) will preclude an uncontrolled boron dilution event in MODE 5 with the RCS loops not filled. Since these valves are required to be secured in position, a frequency of 31 days is sufficient to ensure that they remain closed as required.

SR 3.4.8.4

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 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 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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.4 (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 RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. FSAR, Subsection 15.4.6.

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 emergency 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 prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions.

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.

(continued)

BASES

BACKGROUND (continued)

Two groups of pressurizer heaters can be administratively loaded onto the non-Class 1E emergency buses. The Class 1E 4160-V breakers supplying the non-Class 1E buses are automatically opened upon a safety injection signal, but they can be closed under administrative procedure.

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 FSAR (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.

The maximum pressurizer water level limit satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 1656 cubic feet, which is equivalent to 92% (LI-0459A, LI-0460A, LI-0461A), 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 an emergency power supply. This means that the two required groups of pressurizer heaters must be capable of being powered from a Class 1E 4160-V power supply. This is accomplished by administratively loading the two required

(continued)

LCO (continued)

groups of pressurizer heaters onto the non-Class 1E emergency buses. These non-Class 1E emergency buses are in turn fed from the Class 1E 4160-V buses which can in turn be supplied from the emergency diesel generators or offsite power sources. 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.

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 perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is the need to maintain the availability of pressurizer heaters, capable of being powered from an emergency 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 plant at steady state conditions. Normally the plant will trip in this event 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 restore the plant to operation within the bounds of the safety analyses. 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

(continued)

ACTIONS

A.1 and A.2 (continued)

and restores the unit to operation within the bounds of the safety analyses.

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.

B.1

If one required group of pressurizer heaters is 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 normal station powered heaters.

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, 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 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.

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.

(continued)

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 at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. At VEGP, the pressurizer heaters are in use during normal power operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 15.

2. NUREG-0737, November 1980.

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 of the pop type. The valves are spring loaded and self actuated by direct fluid pressure 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 self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr at a pressurizer pressure of 2560 psig, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine with the reactor operating at 102 percent of engineered safeguards design power. The relief rate is stated at a pressure of 2560 psig which is equivalent to the former set pressure of 2485 psig plus 3% for set pressure tolerance and valve accumulation. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The decrease in set pressure to 2460 psig and increase in tolerance does not significantly affect the relief capacity of 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, 5, and MODE 6 with the reactor vessel head on; however, in MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR, MODE 5, and 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, "Cold Temperature Overpressure Protection System (COPS)."

The upper and lower pressure limits are based on the ± 2% tolerance requirement assumed in the safety analyses. The lift setting is for the ambient conditions associated with

(continued)

BASES

BACKGROUND (continued)

MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

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 FSAR (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, e, and f (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

(continued)

BASES (continued)

LCO

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

The three pressurizer safety valves are set to open at an RCS pressure of 2460 psig, and within the specified tolerance, to avoid exceeding the maximum design pressure SL, and to maintain accident analyses assumptions. The upper and lower pressure tolerance limits are based on the ± 2% tolerance requirements assumed in the safety analyses.

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure.

APPLICABILITY

In MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR, 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 MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR, MODE 5, or MODE 6 (with the reactor vessel head on) because the cold overpressure protection system is in service. Overpressure protection is not required in MODE 6 with reactor vessel head removed.

The Note allows entry into MODE 3 and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR 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 timeframe.

(continued)

BASES (continued)

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. 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.

The CONDITION is modified by two Notes. The first Note states it is not applicable when a Pressurizer Safety Valve is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only intended if a Pressurizer Safety Valve is found to be inoperable. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 5).

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, 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 and to MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR 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, with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR, overpressure protection is provided by the cold overpressure protection system. The change from MODE 1, 2, or 3 to MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR, 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.

(continued)

BASES (continued)

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 OM Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified. The lift settings shall be ≥ 2410 psig and ≤ 2510 psig. The lift setting pressures shall correspond to ambient conditions of the valves at normal operating temperature and pressure.

The pressurizer safety valve setpoint tolerance is ± 2% for OPERABILITY; however, the valves shall be reset to ± 1% during the surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 15.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
5. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

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 safety-related DC solenoid 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 block 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 power supplies to the PORVs, their block valves, and their controls are Class 1E. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two PORVs, each having a relief capacity of 210,000 lb/hr at 2385 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure — High reactor trip setpoint up to and including the design step-load decreases with steam dump. In addition, the PORVs minimize challenges to the pressurizer

(continued)

BASES

BACKGROUND (continued)

safety valves and also may be used for cold overpressure protection. See LCO 3.4.12, "Cold Overpressure Protection System (COPS)."

APPLICABLE SAFETY ANALYSES

Plant operators may employ the PORVs to depressurize the RCS in response to certain plant 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. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs or auxiliary pressurizer spray may 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.

In addition, in the event of an inadvertent safety injection actuation at power, the potential for pressurizer filling and subsequent water relief via the pressurizer safeties (PSVs) is evaluated (FSAR section 15.5.1). Operator action to make one PORV available is credited in the analysis to mitigate this event. If the PORV is available for automatic actuation, the event consequences would be mitigated directly by preventing water relief through the PSVs. However, automatic actuation is not required to mitigate this event. The analysis includes an acceptable delay for the operator to open a block valve and to manually control the PORV if necessary.

The PORVs also provide the safety-related means for reactor coolant system depressurization to achieve safety-grade cold shutdown and to mitigate the effects of a loss of heat sink or an SGTR. They are modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria, pressurizer filling, or reactor coolant saturation 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, automatic actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function. Events that assume this condition include a turbine trip, loss of normal feedwater, and feedwater line break (Ref. 2).

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

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, or loss of heat sink, and to achieve safety grade cold shutdown. The PORVs are considered OPERABLE in either the manual or automatic mode. The PORVs (PV-455A and PV-456A) are powered from 125 V MCCs 1/2AD1M and 1/2BD1M, respectively. If either or both of these MCCs become inoperable, the affected PORV(s) are to be considered inoperable.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied.

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 criteria, exists when conditions dictate closure of the block valve to limit leakage.

An OPERABLE block valve may be either open and energized, 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. Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

The PORVs are required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event, an inadvertent safety injection, and to achieve safety grade cold shutdown. In addition, the block valves 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 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. 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 MODES 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV

(continued)

BASES

APPLICABILITY (continued)

requirements in MODES 4, 5, and 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, instrumentation problems, or other causes that do not create a possibility for a small break LOCA). 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. The PORVs may be considered OPERABLE in either the manual or automatic mode. This permits operation of the plant 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.

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. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

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 the additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D (Ref. 3).

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 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. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B since the PORV may not be capable of mitigating an event if the inoperable block valve is not fully open. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 3). If the block valve is restored within the Completion Time of 72 hours, or within the time limits of the Risk Informed Completion Time, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant 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 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 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 MODES 4, 5, and 6, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

(continued)

BASES

ACTIONS (continued)

E.1, E.2, E.3, and E.4

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block 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 one PORV is restored and one PORV remains inoperable, then the plant will be in Condition B with the time clock started at the original declaration of having two PORVs inoperable. If no PORVs are restored within the Completion Time, then 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 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 MODES 4, 5, and 6, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

F.1

If two block valves are inoperable, it is necessary to restore 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 provides the operator time to correct the situation. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second block valve is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one block valve is inoperable for any reason and a second block valve is found to be inoperable, or if two block valves are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, "Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 3).

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If the Required Actions of Condition F are not met, then 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 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 MODES 4, 5, and 6, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be closed if needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by two Notes. Note 1 modifies this SR by stating that it is not required to be performed with the block valve closed in accordance with the Required Actions of this LCO. Opening the block valves in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable. Note 2 modifies this 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 2, administrative controls require this test be performed in MODE 3 or 4 to adequately simulate operating temperature and pressure effects on PORV operation.

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 this 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 2, administrative controls require this test be performed in MODE 3 or 4 to adequately simulate operating temperature and pressure effects on PORV operation.

(continued)

BASES (continued)

REFERENCES

1. Regulatory Guide 1.32, February 1977.

2. 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 for Light-Water Reactors,' Pursuant to 10 CFR 50.54(f)," June 25, 1990.

3. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, "Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Cold Overpressure Protection Systems (COPS)

BASES

BACKGROUND

The COPS 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 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 COPS MODES or other specified condition in the COPS Applicability.

The reactor vessel material is less tough 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 as temperature is increased.

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.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires both safety injection pumps to be incapable of injection into the RCS and the accumulators to be isolated. 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.

(continued)

BASES

BACKGROUND (continued)

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 safety injection (SI) actuation circuits blocked. Due to the lower pressures in the COPS 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 the safety injection pumps for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The COPS 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.

<u>PORV Requirements</u>

As designed for the COPS, each PORV is signaled to open if the RCS pressure approaches a limit determined by the COPS actuation logic. The COPS actuation logic monitors both RCS temperature and RCS pressure and determines when a condition not acceptable with respect to 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 the COPS. 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.

(continued)

BASES

BACKGROUND

PORV Requirements (continued)

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.

RHR Suction Relief Valve Requirements

During the COPS MODES or other specified condition in the COPS Applicability, 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 and the RHR suction 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 and the RHR suction valves must be open to make the RHR suction relief valves OPERABLE for RCS overpressure mitigation. The RHR suction relief valves are self-actuated 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 COPS 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.

(continued)

BASES (continued)

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, 3, and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. In MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR 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 COPS 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 COPS requirements. Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the COPS acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, as discussed below.

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Reactor coolant pump (RCP) startup with temperature asymmetry between the RCS and steam generators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The following are required during the COPS MODES or other specified condition in the COPS Applicability to ensure that mass and heat input transients do not occur, which either of the COPS overpressure protection means cannot handle:

a. Rendering both safety injection pumps incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Disallowing the start of an RCP if the secondary temperature is more than 50°F above the RCS cold leg temperature in any one loop. With the RHR suction isolation valves open, this value is reduced to 25°F at an RCS temperature of 350°F and varies linearly to 50°F at an RCS temperature of 200°F for RHR design pressure considerations. LCO 3.4.6, "RCS Loops — MODE 4," and LCO 3.4.7, "RCS Loops — MODE 5, Loops Filled," contain notes on this limitation that 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 both centrifugal charging pumps are actuated. Thus, the LCO requires both safety injection pumps to be incapable of injecting into the RCS during the COPS MODES or other specified condition in the COPS Applicability.

Since neither one RCS relief valve nor the RCS vent can handle the pressure transient caused by accumulator injection when RCS temperature is low, the LCO also requires accumulator 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 fixed in their open positions.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limits shown in the PTLR. The setpoints are derived by analyses that model the performance of the COPS, assuming

(continued)

BASES

APPLICABLE SAFETY ANALYSES

PORV Performance (continued)

the mass injection transient of two centrifugal charging pumps and the positive displacement pump injecting into the RCS, and the heat injection transient of starting an RCP with the RCS 50°F colder than the secondary coolant. 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 ensure the Reference 1 P/T limits will be met.

---NOTE---------------------------------------
Although the positive displacement pump (PDP) was replaced with the normal charging pump (NCP), the current mass injection transient analysis assumes two centrifugal charging pumps and the positive displacement pump. Westinghouse performed an evaluation of the effect of replacing the PDP with the NCP and obtained acceptable results without reanalysis of the mass injection transient. Reference Westinghouse letter, GP-16838 from J. L. Tain to J. B. Beasley, Jr., dated August 13, 1998, COPS PORV Setpoint for New Charging Pump.

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the COPS analysis limits. 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, "RCS Pressure and Temperature (P/T) Limits," 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.

RHR Suction Relief Valve Performance

The RHR suction relief valves do not have variable pressure and temperature lift setpoints like the PORVs. Analyses show that one RHR suction relief valve with a setpoint at or between 440 psig and 460 psig (Ref. 9) will pass flow greater than that required for the limiting COPS transient while maintaining RCS pressure less than the P/T limit curve.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

RHR Suction Relief Valve Performance (continued)

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 COPS.

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 1.5 square inches (based on an equivalent length of 10 feet of pipe, i.e., a vent capable of relieving 685 gpm waterflow at 722 psig) is capable of mitigating the allowed COPS overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the COPS configuration, with both safety injection pumps incapable of injecting into the RCS, 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 COPS satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

LCO

This LCO requires that the COPS is OPERABLE. The COPS 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 and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires both safety injection pumps to be incapable of injecting into the RCS and all accumulator discharge isolation valves closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

(continued)

BASES

LCO (continued)

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two RCS relief valves, as follows:

    1. Two OPERABLE PORVs; or

       A PORV is OPERABLE for the COPS 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. The PORVs (PV-455A and PV-456A) are powered from 125 V MCCs 1/2AD1M and 1/2BD1M, respectively. The PORVs are to be considered OPERABLE whenever these MCCs are available to supply power.

    2. Two OPERABLE RHR suction relief valves; or

       An RHR suction relief valve is OPERABLE for the COPS when its RHR suction isolation valve and its RHR suction valve are open, its setpoint is at or between 440 psig and 460 psig, and testing has proven its ability to open at this setpoint.

    3. One OPERABLE PORV and one OPERABLE RHR suction relief valve; or

b. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of $\geq$ 1.5 square inches (based on an equivalent length of 10 feet of pipe, i.e., capable of relieving 685 gpm at 722 psig).

   Each of these methods of overpressure prevention is capable of mitigating the limiting COPS transient.

APPLICABILITY

This LCO is applicable in MODE 4 with any RCS cold leg temperature $\leq$ the COPS arming temperature specified in the PTLR, in MODE 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 in MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR. 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

(continued)

BASES

APPLICABILITY (continued)

OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures > the COPS arming temperature specified in the PTLR.

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 when little or no time allows operator action to mitigate the event.

The Applicability is modified by a Note stating that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

ACTIONS

A Note modifies the ACTIONS table. The Note prohibits the application of LCO 3.0.4b for entry into MODE 4 as well as entry into MODE 6 with the vessel head on from MODE 6 and MODE 5 from MODE 6 with the vessel head on. There is an increased risk associated with entering MODE 4 from MODE 5, MODE 6 with the reactor vessel head on from MODE 6, and MODE 5 from MODE 6 with the reactor vessel head on with COPS inoperable. The provisions of LCO 3.0.4b, 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 these circumstances.

(continued)

BASES

ACTIONS (continued)

A.1

With one or more safety injection pumps capable of injecting into the RCS, RCS overpressurization is possible.

Rendering the safety injection pumps incapable of injecting into the RCS within 4 hours to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

B.1, C.1, and C.2

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 isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > the COPS arming temperature specified in the PTLR, an accumulator pressure of 678 psig cannot exceed the COPS limits if the accumulators are fully injected. Depressurizing the accumulators below the COPS limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and that the likelihood that an event requiring COPS during this time is small.

D.1

In MODE 4 with any RCS cold leg temperature ≤ the COPS arming temperature specified in the PTLR, 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 the facts 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.

(continued)

BASES

ACTIONS (continued)

E.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 7). 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.

F.1

The RCS must be depressurized and a vent must be established within 12 hours when:

a. Both required RCS relief valves are inoperable; or

b. A Required Action and associated Completion Time of Condition A, C, D, or E is not met; or

c. The COPS is inoperable for any reason other than Condition A, B, C, D, or E.

The vent must be sized $\geq$ 1.5 square inches (based on an equivalent length of 10 feet of pipe) to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable COPS MODES or other specified condition in the COPS Applicability. 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, both safety injection pumps are verified incapable of injecting into the RCS, and the accumulator discharge isolation valves are verified closed and locked out.

The safety injection pumps are rendered incapable of injecting into the RCS through at least two independent means such that a single failure or single action will not result in an injection into the RCS.

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

SR 3.4.12.3

Each required RHR suction relief valve shall be demonstrated OPERABLE by verifying its RHR suction isolation valves are open and by testing it in accordance with the INSERVICE TESTING PROGRAM. This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO. For Train A, the RHR suction relief valve is PSV-8708A and the suction isolation valves are HV-8701A and B. For Train B, the RHR suction relief valve is PSV-8708B and the suction isolation valves are HV-8702A and B.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The RHR suction valves are verified to be opened.

The ASME OM Code (Ref. 8), test per INSERVICE TESTING PROGRAM verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

SR 3.4.12.4

The RCS vent of ≥ 1.5 square inches (based on an equivalent length of 10 feet of pipe) is proven OPERABLE by verifying its open condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.4 (continued)

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 met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12 b.

SR 3.4.12.5

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. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required to be removed, and the manual operator is not required to be 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 3.4.12.6

Performance of a COT is required within 12 hours after decreasing RCS temperature to ≤ the COPS arming temperature specified in the PTLR 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.

A Note has been added indicating that this SR is required to be performed 12 hours after decreasing RCS cold leg temperature to ≤ the COPS arming temperature specified in the PTLR. The 12 hours considers the unlikelihood of a low temperature overpressure event during this time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.7

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. FSAR, Chapter 15
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. Generic Letter 90-06.
8. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
9. Westinghouse Letter GP-13419, RHR Open Permissive Setpoint.

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, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can allow 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 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 auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

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

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

Pressure boundary LEAKAGE is prohibited as the leak itself could cause further RCPB deterioration, resulting in higher LEAKAGE.

b. <u>Unidentified LEAKAGE</u>

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Separating the sources of leakage (i.e., leakage from an identified source versus leakage from an unidentified source) is necessary for prompt identification of potentially adverse conditions, assessment of the safety significance, and corrective action.

(continued)

BASES

LCO (continued)

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 controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE).

d. Primary to Secondary LEAKAGE through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

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.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual 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 in the allowable identified LEAKAGE.

(continued)

BASES (continued)

ACTIONS

A.1

If pressure boundary LEAKAGE exists, the affected component, pipe, or vessel must be isolated from the RCS by a closed manual valve, closed and de-activated automatic valve, blind flange, or check valve within 4 hours. While in this condition, structural integrity of the system should be considered because the structural integrity of the part of the system within the isolation boundary must be maintained under all licensing basis conditions, including consideration of the potential for further degradation of the isolated location. Normal LEAKAGE past the isolation device is acceptable as it will limit RCS LEAKAGE and is included in identified or unidentified LEAKAGE. This action is necessary to prevent further deterioration of the RCPB.

B.1

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

C.1 and C.2

If primary to secondary LEAKAGE is not within limit, or if any of the Required Actions and associated Completion Times cannot be met, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. The reactor must be placed in a MODE in which overall plant risk is reduced. This is done by placing the unit in at least MODE 3 within 6 hours and MODE 4 within the next 6 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 6). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 6, the steam turbine driven Auxiliary Feedwater Pump must be available to remain

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

(continued)

BASES (continued)

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. 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. The Surveillance is modified by three Notes. Note 1 states that this SR is not required to be performed in MODES 3 and 4 until 12 hours of steady state operation have been established. In all cases, this SR is required to be performed prior to entering MODE 2 to ensure the assessment of RCS leakage prior to critical operation.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and Note 2 requires the Surveillance to be performed when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 3 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 12 hour Frequency after steady state operation has been achieved provides for those situations where a transient occurs, and the duration of the transient is such that the 72 hour Frequency plus the 25% extension allowed by SR 3.0.2 would be exceeded. In this event, the SR would be due within 12 hours after steady state operation has been reestablished. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program

(continued)

BASES

SURVEILLANCE REQUIREMENTS

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 3.4.17, "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 the EPRI guidelines (Ref. 5).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.

2. Regulatory Guide 1.45, May 1973.

3. FSAR, Section 15.

4. NEI 97-06, "Steam Generator Program Guidelines."

5. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

6. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

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 overpressure 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.

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.

(continued)

BASES

BACKGROUND (continued)

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System;

b. Safety Injection System; and

c. Chemical and Volume Control System.

The PIVs are listed in the FSAR, Section 5.4 (Ref. 6).

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 typically designed for 600 psig, overpressurization failure of the RHR low pressure line would 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).

LCO

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on

(continued)

BASES

LCO
(continued)

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.

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.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in the RHR mode of operation.

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 each flow path allows separate entry into a Condition. 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.

(continued)

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 valves 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 the Action and the low probability of a second valve failing during this time period.

B.1 and B.2

If leakage cannot be reduced, the system cannot be isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

C.1

The inoperability of the RHR 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 suction isolation valve interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This Action accomplishes the purpose of the interlock.

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.

The acceptance criteria for RCS PIV leakage is the equivalent of ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig. Test pressures < 2255 psig but > 350 psig are allowed. Observed leakage shall be adjusted for the actual test pressure up to 2235 psig assuming the leakage to be directly proportional to the pressure differential to the one-half power.

For the 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

Testing is to be performed every 18 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 18 month Frequency is consistent with 10 CFR 50.55a(f) (Ref. 9) as contained in the INSERVICE TESTING PROGRAM, is within the frequency allowed by the American Society of Mechanical Engineers (ASME) OM Code (Ref. 7), and is based on the need to perform such surveillances under the conditions that apply during an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

In addition, for systems rated at less than 50% design pressure, testing must be performed once after any RCS PIV, whether a first or second isolation valve has been actuated to ensure tight reseating except for RHR suction isolation valves HV-8701 A/B and HV-8702 A/B. The exception for valves HV-8701 A/B and HV-8702 A/B is based on the existence of full closure indication in the control room, interlocks to prevent inadvertent opening when RCS pressure is above the RHR system design pressure, and high pressure alarms. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. For the systems rated at less than 50% design pressure, testing must be performed within 24 hours after the valve has been actuated. Within 24 hours is a reasonable and practical time limit for performing this test after the actuation of a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1, 2, 3, and 4, but the SR is not required to be performed during MODES 3 and 4. The entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months (except for valves HV-8701 A/B and HV-8702 A/B). In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

SR 3.4.14.2

Verifying that the RHR System suction isolation valve interlock is OPERABLE ensures that RCS pressure will not pressurize the RHR system beyond 125% of its design pressure of 600 psig. The interlock setpoint that prevents the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.2 (continued)

valves from being opened is set so the actual RCS pressure must be < 450 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded. To ensure that the RHR relief valves will not lift, the actual interlock setpoint used in performing the surveillance is < 365 psig, and takes into consideration various allowances for relief valve setting variation, transmitter elevation, and the total instrument channel uncertainty. The total instrument channel uncertainty is calculated in accordance with reference 10, and the allowance for process instrumentation (rack drift) is 1%. Once the interlock setpoint is initially reached, administrative controls ensure that the RHR suction isolation valves are closed prior to reaching an RCS pressure that could cause the RHR suction relief valves to open. Due to the bistable reset design, the valves could be opened at a pressure above the interlock setpoint, but below the reset pressure. The administrative controls ensure that the valves will not be opened if RCS pressure exceeds 365 psig after RCS pressure has decreased below the interlock setpoint.

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. FSAR Section 5.4.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
8. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.
9. 10 CFR 50.55a(f).
10. WCAP-11269, Rev. 1, Westinghouse Setpoint Methodology for Protection Systems.

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.

Systems employed for detecting leakage to the containment from unidentified sources are:

- Containment atmosphere airborne particulate radioactivity monitor;
- Containment atmosphere gaseous radioactivity monitor;
- Containment air cooler condensate flow monitor; and
- Containment sump level monitor.

The containment airborne particulate radioactivity monitor draws an air sample from containment via a sample pump. The sample is then passed through a particulate filter with detectors. Particulate activity can be correlated with the coolant fission and corrosion product activities.

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BASES

BACKGROUND (continued)

The containment atmosphere gaseous radioactivity monitor draws air continuously from the containment atmosphere through a gas monitor. This sample stream flows continuously through a fix shielded volume where its activity is monitored. Gaseous radioactivity can be correlated with the gaseous activity of the reactor coolant.

The containment air cooler condensate monitoring system permits measurement of the liquid runoff from the containment cooler units. It consists of a drain collection header, a vertical standpipe, valving, and standpipe level instrumentation for the coolers. The condensation from the containment coolers flows via the collection header to the vertical standpipe, and a differential pressure transmitter provides standpipe level signals. The system provides measurements of low leakages by monitoring standpipe level increase versus time. Drainage flow rate from the cooling units due to normal condensation is calculated for the ambient (background) atmospheric conditions present within the containment. With the initiation of an additional or abnormal leak, the containment atmosphere humidity and condensation runoff rate both begin to increase, the water level rises in the vertical pipe, and the high condensate flow alarm is actuated. The condensate flow rate is a function of containment humidity, nuclear service cooling water (NSCW) temperature, and containment purge rate.

The containment normal or reactor cavity sumps can also be used to detect RCS leakage. Since a leak in the RCS would result in reactor coolant flowing into the containment normal or reactor cavity sumps, leakage would be indicated by a level increase in the sump. The actual reactor coolant leakage rate can be established from the increase above the normal rate of change of sump level. Indication of an increasing sump level is transmitted from the sump to the control room level indicator by means of a sump level transmitter. The system provides measurements of low leakages by monitoring level increase versus time. A check of other instrumentation would be required to eliminate possible leakage from nonradioactive systems as a cause of an increase in sump level.

The above-mentioned LEAKAGE detection 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.

(continued)

BASES

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 unit and the public.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36 (c)(2)(ii).

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 plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires three instruments to be OPERABLE.

The containment normal or reactor cavity sumps are used to collect unidentified LEAKAGE. The LCO requirements apply to the total amount of unidentified LEAKAGE collected in the containment normal and reactor cavity sumps. Since a leak in the primary system would result in reactor coolant flowing into the containment normal or reactor cavity sumps, leakage would be indicated by a level increase in the sumps. Indication of an increasing sump level is transmitted from the sump to the control room level indicator by means of a sump level transmitter. The system provides measurements of low leakages by monitoring level increase versus time. The leakage rate can also be determined from the frequency of sump pump operation. Under normal conditions, the containment normal and reactor cavity sump pumps operate very infrequently. Gross leakage can be surmised from more frequent pump operation. Sump level and pump running indications are provided in the control room to alert the operators.

The detection capabilities of the containment normal sump and reactor cavity sump are described in Reference 3. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the containment normal and reactor cavity sumps and it may take longer than 1 hour to

(continued)

BASES

LCO (continued)

detect a 1 gpm increase in unidentified LEAKAGE, 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, may be detected by the gaseous or particulate 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 initial reactor startup, following a refueling outage, and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel assembly cladding contamination or cladding defects. If there are few fuel assembly cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate containment atmosphere radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate containment atmosphere radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in unidentified LEAKAGE within approximately 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors, as described in Reference 3.

An increase in humidity of the containment atmosphere could indicate the release of water vapor to the containment. The containment air cooler condensate flow rate system provides measurements of low leakages by monitoring a standpipe level increase versus time. Condensate flow from the containment air coolers is instrumented to detect when there is an increase above the normal value by 1 gpm. The time required to detect a 1 gpm increase above the normal value varies based on environmental and system conditions and may take longer than 1 hour. This sensitivity is acceptable for containment air cooler condensate flow rate monitor OPERABILITY.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump monitors, in combination with a gaseous or particulate radioactivity monitor and/or a containment air cooler condensate flow rate monitor, provides an acceptable minimum.

(continued)

BASES (continued)

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

With one containment sump monitor inoperable, the remaining containment sump monitors, the containment atmosphere radioactivity monitor, and/or the containment air cooler condensate flow rate monitor will provide indications of changes in leakage. Together with these monitors, 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.

B.1 and B.2

With two or more containment sump monitors inoperable, no other form of sampling or monitors can provide the equivalent information; however, the containment atmosphere radioactivity and/or containment air cooler condensate flow rate monitors will provide indications of changes in leakage. Together with these remaining monitors, 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.

Restoration of at least two sump monitors to OPERABLE status within a Completion Time of 30 days is required to regain most of this function and allow operation to continue under the provisions of Condition A. This Completion Time is acceptable, considering the remaining OPERABLE atmosphere radioactivity and/or condensate flow rate monitors and the Frequency and adequacy of the RCS water inventory balance required by Action B.1.

(continued)

BASES

ACTIONS (continued)

C.1.1, C.1.2, C.2.1, and C.2.2

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 monitors. Alternatively, continued operation is allowed if the air cooler condensate flow rate monitoring system is OPERABLE, provided grab samples are taken every 24 hours.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

D.1 and D.2

With the required containment air cooler condensate flow rate monitor inoperable, alternative action is again required. Either SR 3.4.15.2 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.
Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of the containment air cooler condensate flow rate monitor to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS LEAKAGE.

E.1 and E.2

With both required containment atmosphere gaseous and particulate radioactivity monitors and the required containment air cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the containment sump monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable required

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

F.1, F.2.1, and F.2.2

With the required containment sump monitors and the required containment air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the required containment atmosphere radiation monitor. A Note clarifies that this Condition is applicable when the only OPERABLE monitor is the containment atmosphere gaseous radiation monitor. The containment atmosphere gaseous radioactivity monitor typically cannot detect a 1 gpm leak within 1 hour when the 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 plant will not be operated in a degraded configuration for a lengthy time period.

G.1 and G.2

If a Required Action of Condition A, B, C, D, E, or F cannot be met, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

Required Action G.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

H.1

With all required leakage detection systems inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required. For the purpose of this Condition, the leakage detection systems consist of the three systems described below in items a, b, and c, respectively:

a. The containment normal sumps level and reactor cavity sump monitors;

b. One containment atmosphere radioactivity monitor (gaseous or particulate); and

c. Either the containment air cooler condensate flow rate or a containment atmosphere gaseous or particulate radioactivity monitoring system not taken credit for in item b.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1 and SR 3.4.15.2

These SRs require the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor and containment sump monitors. The check gives reasonable confidence that the channels are operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.3

SR 3.4.15.3 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 verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.4, SR 3.4.15.5, and SR 3.4.15.6

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

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. FSAR, Subsection 5.2.5.

4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the exclusion area boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident.

The LCO limits specific activity for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the exclusion area boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The limits on the specific activity of the reactor coolant ensures that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes that the reactor has been operating at the maximum allowable Technical Specification limit for primary coolant activity and primary to secondary leakage for sufficient time to establish equilibrium concentrations of radionuclides in the reactor coolant and in the secondary coolant.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The analysis is for two cases of reactor coolant specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with concurrent large iodine spike that increases the iodine release rate from the fuel to the coolant to a value 500 times greater than the release rate corresponding to the initial primary system iodine concentration. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The analysis also assumes a loss of offsite power at the same time as the SGTR event. 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 coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The safety analysis shows the radiological consequences of an SGTR accident are well within the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the applicable specification, for more than 48 hours. The safety analysis has concurrent and pre-accident iodine spiking levels up to 60.0 μCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

probability of a SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

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

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the exclusion area boundary during the Design Basis Accident (DBA) will be a small fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the exclusion area boundary during the DBA will be a small fraction of the allowed whole body dose.

The SGTR accident analysis (Ref. 2) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to exclusion area boundary doses that exceed the 10 CFR 100 dose guideline limits.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

(continued)

BASES (continued)

ACTIONS

A Note permits the use of the provisions of LCO 3.0.4c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. 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 unit remains at or proceeds to power operation.

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

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is acceptable because of the low probability of an SGTR accident occurring during this period.

<u>B.1</u>

With the gross specific activity in excess of the allowed limit, the unit must be placed in a MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F 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 gross specific activity of the reactor coolant. Gross specific activity is basically a quantitative measure of radionuclides with half lives longer than 14 minutes, excluding all radioiodines. It is the sum of concentrations of individually identified nuclides, liquid and gaseous, counted within 2 hours after the sample is taken and extrapolated back to when the sample was taken. Determination of the contributors to the gross specific activity shall be based upon those gamma energy peaks identifiable with a 95% confidence level. The latest available data may be used for pure beta-emitting radionuclides. This Surveillance provides an indication of any increase in gross 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 Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500°F. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.2 (continued)

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 fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the specific activity for each radionuclide identified in the reactor coolant with half lives longer than 14 minutes, excluding all radioiodines. The specific activities for these individual radionuclides shall be used in the determination of $\bar{E}$ for the reactor coolant sample. Determination of the contributors to $\bar{E}$ shall be based upon those energy peaks identifiable with a 95% confidence level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours, if the surveillance requirement had not been performed within the last 184 days, such as during a refueling outage. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. 10 CFR 100.11, 1973.

2. FSAR, Subsection 15.6.3.

BASES

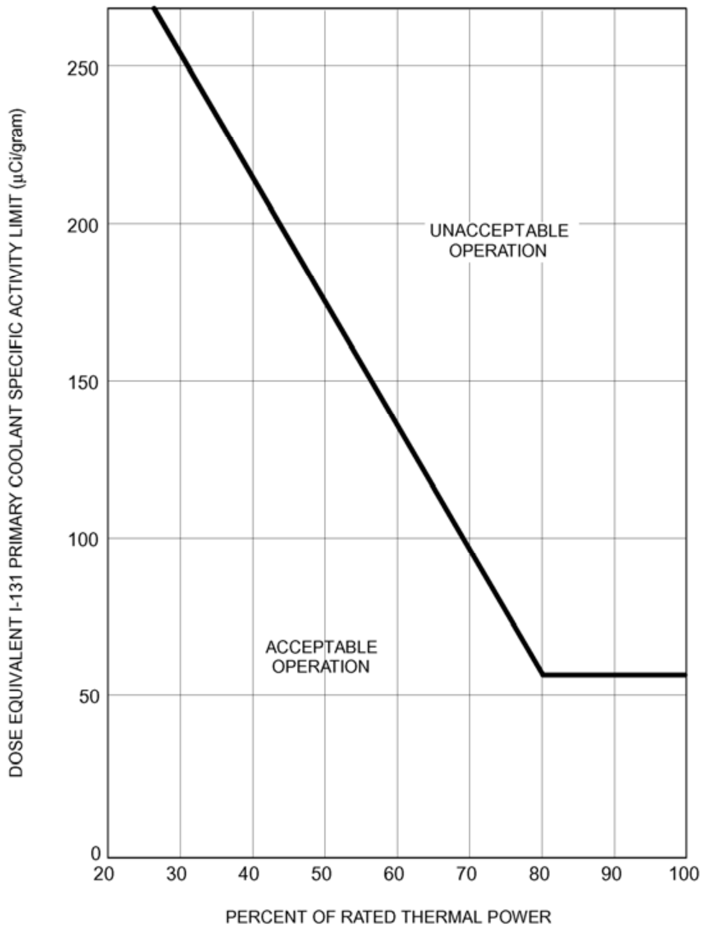

Figure 3.4.16-1

Reactor Coolant Dose Equivalent I-131 Reactor Coolant Specific Activity Limit versus Percent of Rated Thermal Power with the Reactor Coolant Specific Activity >1 µCi/gram Dose Equivalent I-131

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 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.

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

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, “RCS Operational LEAKAGE,” 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 only briefly released to the atmosphere via safety valves and the majority is discharged to the main condenser.

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.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be 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 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

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

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, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. Portions of the tube below 15.2 inches below the top of the

(continued)

BASES

LCO (continued)

tubesheet are excluded from the periodic SG tube inspection requirements (Ref. 7). 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. 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. 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

(continued)

BASES

LCO (continued)

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 analysis assumes that accident induced leakage does not exceed 1 gpm per SG. 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.

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.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

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 3.4.17.2. 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.

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 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. 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

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. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, nondestructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. 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 3.4.17.2

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.2 (continued)

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.

REFERENCES

1. NEI 97-06, “Steam Generator Program Guidelines.”
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 100.
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.”
7. License Amendment Nos. 167 and 149, "Vogtle Electric Generating Plant, Units 1 and 2, Issuance of Amendments Regarding Revision to Technical Specifications 5.5.9, "Steam Generator (SG) Program," and 5.6.10, "Steam Generator Tube Inspection Report," (TAC Nos. ME8313 and ME8314),” September 10, 2012.

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.

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.

(continued)

BASES

BACKGROUND (continued)

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 (Ref. 2). 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.

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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 3) will be met following a LOCA:

a. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For both the large and small break LOCA analyses, a nominal contained accumulator water volume 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, an increase in water volume is a peak clad temperature penalty. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis makes a conservative assumption with respect to ignoring or taking credit for line water volume from the accumulator to the check valve. The safety analysis assumes values of 6433 gallons and 7031 gallons. To allow for instrument inaccuracy, values of 6555 gallons (29.2% of instrument span) and 6909 gallons (70.7% of instrument span) are specified.

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 large and 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 maximum nitrogen cover pressure limit prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 2 and 4).

The accumulators satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

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. 3) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed at or above 1000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure 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. 3) limit of 2200°F.

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.

(continued)

BASES (continued)

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. The accumulators will discharge following a large main steam line break, however, their impact is minor with respect to this limiting design basis event. 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 24 hours. 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 24 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 plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev. 1 (Ref. 5)

C.1

With two or more accumulators inoperable for reasons other than boron concentration out of limits, the Required Action is to restore sufficient inoperable accumulators to OPERABLE status within 1 hour or, in accordance with the Risk Informed Completion Time Program to regain the safety function. The CONDITION is modified by two Notes. The first Note states that the Condition is not applicable when two or more accumulators are intentionally made inoperable. The Required Action is not intended for voluntary removal of redundant components from service. The Required Action is only applicable if one accumulator is inoperable for any reason and additional

(continued)

BASES

ACTIONS

C.1 (continued)

accumulators are found to be inoperable, or if two or more accumulators are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 7).

D.1 and D.2

If the accumulator cannot be returned 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 MODE 3 within 6 hours and pressurizer pressure reduced to ≤ 1000 psig 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve (HV-8808A, B, C, D) 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

The borated water volume (LI-0950, 0951, 0952, 0953, 0954, 0955, 0956, 0957) and nitrogen cover pressure (PI-0960A&B, 0961A&B, 0962A&B, 0963A&B, 0964A&B, 0965A&B, 0966A&B, 0967A&B) are verified for each accumulator. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

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. Sampling the affected accumulator within 6 hours after a 1% volume increase (7% 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 if the added water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 6).

SR 3.5.1.5

Verification that power is removed from each accumulator isolation valve operator when the pressurizer pressure is > 1000 psig 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows power to be supplied to the motor operated isolation valves when pressurizer pressure is ≤ 1000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

(continued)

BASES (continued)

REFERENCES

1. Deleted.
2. FSAR, Chapter 6.
3. 10 CFR 50.46.
4. FSAR, Chapter 15.
5. WCAP-15049-A, Rev. 1, April 1999.
6. NUREG-1366, February 1990.
7. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

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 7.5 hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the potential for boiling in the top of the core and ensure boron precipitation never occurs.

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

(continued)

BASES

BACKGROUND (continued)

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 beginning of the injection phase of LOCA recovery, a 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 and then divides again into four supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the SI pumps combines and divides into four supply lines, each of which feeds an injection line to one RCS cold leg. The discharge from each RHR pump feeds two injection lines each. Throttle valves for the CCP and SI injection lines 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.

During the injection phase, between the RWST low-low level and empty level, the centrifugal charging pumps and SI pumps are placed in series with the RHR pumps such that the centrifugal charging pumps’ and SI pumps’ suctions are aligned to the discharge of the RHR pumps.

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.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps continue to supply the other ECCS pumps. Initially, recirculation is accomplished by injection into the cold legs. Subsequently, recirculation can be accomplished by injection into both the hot and cold legs.

(continued)

BASES

BACKGROUND (continued)

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 (EDGs). 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 sump, covered in LCO 3.5.1, "Accumulators," LCO 3.5.4, "Refueling Water Storage Tank (RWST)," and LCO 3.6.7, “Containment Sump,” provide the cooling water necessary to meet GDC 35 (Ref. 1).

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. Maximum fuel element cladding temperature is $\leq 2200°F$;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount 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 (Refs. 3 and 4). 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. A large break LOCA event, with loss of offsite power and a single failure disabling one ECCS train; and

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.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

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.

(continued)

BASES (continued)

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.

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."

As indicated in the Note, either flow path may be isolated in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room.

In MODES 5 and 6, plant 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."

(continued)

BASES (continued)

ACTIONS

A.1

With one or more trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must 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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 8).

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 supporting systems are not available.

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 this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 6 describes situations in which one 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable trains cannot be returned 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 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 plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in the correct position by placing the power lockout switches in the correct position 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 6, 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, 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 (continued)

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 an individual who can rapidly close the system vent flow path if directed.

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 noncondensinble gas into the reactor vessel.

Selection of ECCS locations susceptible to 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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.3 (continued)

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 the maximum potential accumulated gas void volume has been evaluated and determined to not challenge the 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 OM Code (Ref. 7). This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies that the measured performance is within an acceptable tolerance of the original pump baseline performance. SRs are specified in the INSERVICE TESTING PROGRAM, which encompasses the ASME OM Code. The ASME OM Code provides the activities and Frequencies necessary to satisfy the requirements.

In addition to the acceptance criteria of the INSERVICE TESTING PROGRAM, performance of this SR also verifies that pump performance is greater than or equal to the performance assumed in the safety analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.5 and SR 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI and RWST level low-low (for RHR semiautomatic switchover to the containment sump) signal and that each ECCS pump starts on receipt of an actual or simulated SI 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.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. FSAR, Section 6.3, ECCS.
4. FSAR, Chapter 15, "Accident Analysis."
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. IE Information Notice No. 87-01.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
8. Vogtle Electric Generating Plant, Unit 1 and 2 Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

BASES

REFERENCES (continued)	8.	Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS — Shutdown

BASES

BACKGROUND

In MODE 4, the ECCS is available to be manually started to provide water and negative reactivity to the reactor core, if needed. 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 sump can be injected into the Reactor Coolant System (RCS). The 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.

APPLICABLE SAFETY ANALYSES

Based on the stable reactivity conditions and reduced core cooling requirements while in the Applicability, sufficient time exists for manual actuation of the required ECCS if needed, and automatic initiation is not required.

Only one train of ECCS is required. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS shutdown satisfies criterion 4 of 10 CFR 50.36 (c)(2)(ii).

LCO

In MODE 4, one ECCS train is required to be OPERABLE to ensure that ECCS flow is available to the core, if needed.

(continued)

BASES

LCO (continued)

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.

If ECCS actuation is needed, 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.

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.

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 Note prohibits the application of LCO 3.0.4b to an inoperable ECCS centrifugal charging pump subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS centrifugal charging pump subsystem, and the provisions of LCO 3.0.4b, 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.

(continued)

BASES

ACTIONS (continued)

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to an event or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of im-mediately 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 the required RHR pump and heat exchanger inoperable, it would be unwise to require the plant 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 the required ECCS centrifugal charging subsystem inoperable, and at least 100% of the ECCS flow equivalent to a singe OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. Since the 72 hour Completion Time is acceptable when the unit is in MODES 1, 2, and 3 (Ref. 5) and MODE 4 represents less severe conditions for the initiation of an event, the 72 hour Completion Time is also acceptable for MODE 4. This allows increased flexibility in plant operations under circumstances when components in the required train may be inoperable, but ECCS remains capable of delivering 100% of the required flow.

C.1

With no ECCS centrifugal charging subsystem OPERABLE, due to the inoperability of the centrifugal charging pump or flow path from the RWST, the plant is not prepared to provide high pressure response, if needed. The 1 hour Completion Time to

(continued)

BASES

ACTIONS

C.1 (continued)

restore at least one ECCS 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 plant in MODE 5, where an ECCS train is not required.

D.1

When the Required Actions of Conditions B or C 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 for SRs 3.5.2.3, 3.5.2.4 and 3.5.2.7 apply. Note that these Surveillance descriptions were written for a specification that is applicable in MODEs 1, 2, and 3, and SR 3.5.3.1 is applicable for MODE 4. However, the descriptions provided for SRs 3.5.2.3, 3.5.2.4, and 3.5.2.7 are applicable to MODE 4 as well. SR 3.5.3.1 is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and is not otherwise inoperable. This allows operation in the RHR mode during MODE 4, if necessary.

REFERENCES

None.

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 — Empty Level 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 and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

(continued)

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.

The contents of the RWST are protected from freezing by a sludge mixing system which includes an electric circulation heater. However, the sludge mixing pump and the electric circulation heater connected to the tank are not safety grade or seismically qualified. Therefore, an isolation capability is provided to prevent a loss of the RWST water volume. Two train-oriented, air-operated, seismically qualified valves mounted in series on the suction line to the sludge mixing pump provide this capability. When closed, they isolate the safety-related portion of the line (connecting to the RWST) from its nonsafety-related, nonseismic portion connected to the sludge mixing pump. Both valves fail closed upon the loss of instrument air and/or control power. Each valve is automatically actuated to close upon a RWST low-level signal from a redundant level switch in its respective safety train. The capability for remote-manual isolation from the control room is also provided. The status of each isolation valve is displayed by the indicating lights on the individual handswitches in the control room. The closure of either isolation valve will cause an automatic trip of the sludge mixing pump and the electric circulation heater due to low flow.

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; and

c. The reactor remains subcritical following a LOCA.

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

(continued)

BASES

BACKGROUND (continued)

reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive stress corrosion of mechanical components and systems inside the containment.

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 (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." 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 main steam line break (MSLB) analysis to ensure the required shutdown capability. 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.

The MSLB analysis has considered a delay associated with the interlock between the VCT and RWST isolation valves, and the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 39 seconds without offsite power (includes 12 seconds for the Emergency Diesel Generator). This response time includes an electronics delay, a stroke time for the RWST valves, and a stroke time for the VCT valves.

For a large break LOCA analysis, the minimum water volume limit of 499,091 gallons and the lower boron concentration limit of 2400 ppm 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 upper limit on boron concentration of 2600 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.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 44°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. (The reduction in containment pressure correspondingly reduces the density of the vented steam. This reduces the flow of steam out of the core, which translates into a decrease in the ECCS flooding rate. This decrease in the flooding rate causes the increase in peak clad temperature.) The upper temperature limit of 116°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 RWST satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

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, temperature limits, and have the capability of being automatically isolated from the sludge mixing system as 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. 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

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.

(continued)

BASES

ACTIONS (continued)

B.1 and C.1

The two sludge mixing pump isolation valves serve to isolate the non-safety grade mixing system from the RWST when the RWST level reaches the low level alarm. With this isolation capability inoperable, the potential exists for the inadvertent draining of the RWST below the required level via a failure (breach) in the sludge mixing system. With one valve inoperable (Required Action B.1) isolation capability is maintained via the second isolation valve. Consequently, 24 hours is allowed to return the valve to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

With both valves inoperable (Required Action C.1), the potential exists for an inadvertent draining of the RWST below the required level via a failure (breach) in the sludge mixing system. Therefore, action must be taken to restore the isolation valve to OPERABLE status within 24 hours. Unlike Required Action B.1, no provision is made for a Risk Informed Completion Time (Ref. 3).

D.1

If the isolation valve(s) cannot be restored to OPERABLE status within the required time, action must be taken within the following 6 hours to isolate the sludge mixing system from the RWST. This may be accomplished by closing the manual isolation valve(s) or deenergizing the OPERABLE solenoid pilot valve. The times allowed for restoration or remedial action are reasonable considering the low probability of an event occurring during the specified time that would require the RWST, coincident with a sludge mixing system failure that would drain the RWST.

E.1

With the RWST inoperable for reasons other than Condition A, B, or C (e.g., water volume), it must be restored to OPERABLE status within 1 hour. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. However, a risk informed completion time may not be used if the RWST is inoperable due to inadequate water volume.

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 plant 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.

(continued)

BASES

ACTIONS

E.1 (continued)

This Condition is modified by two Notes. The first Note states it is not applicable when the RWST is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only intended if the RWST is found inoperable. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 3).

F.1 and F.2

Condition F is applicable to Conditions A or E. If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action F.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

(TI-10982)

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 temperature is ≥ 40°F. With ambient air temperatures ≥ 40°F, the RWST temperature should not exceed the limits. Since ambient air temperatures do not exceed the RWST upper temperature limit, the requirement to verify RWST temperature only when the ambient temperature is below 40°F is acceptable.

SR 3.5.4.2

(LI-0990A&B, LI-0991A&B, LI-0992A, LI-0993A)

The RWST water volume (686,000 gallons) should be verified to be above the required minimum level 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 3.5.4.3

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 that boron precipitation in the core will not occur. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that the effect of chloride and stress corrosion on mechanical systems and components will be minimized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.4

(LI-0990, LI-0991)

This Surveillance demonstrates that each automatic sludge mixing pump isolation valve actuates to the closed position on an actual or simulated RWST low-level signal. Automatic isolation of this system is required to ensure adequate RWST level during a Design Bases Event. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.

2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

3. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

This LCO is applicable only to those units that utilize the centrifugal charging pumps for safety injection (SI). 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 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 LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging 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.

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. Seal injection flow satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

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 reactor coolant pump seal injection needle valves to provide a total seal injection flow in the acceptable region of Figure B 3.5.5-1 at a given pressure differential between the charging header and the RCS. The centrifugal charging pump discharge header pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed centrifugal charging pump discharge header pressure result in a conservative valve position should RCS pressure decrease. The flow limits established by Figure B 3.5.5-1 are consistent with the accident analyses.

The limits on seal injection flow must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.

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.

(continued)

BASES (continued)

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 8 hours from the time the flow is known to be above the limit to perform SR 3.5.5.1 and 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 to within the limit. 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 plant 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.

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. A differential pressure that is above the reference minimum value is established between the charging header (PT-120, charging header pressure) and the RCS, and the total seal injection flow is verified to be within the limits determined in accordance with the ECCS safety analysis (Ref. 3). The seal water injection flow limits are as shown in figure B 3.5.5-1. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1 (continued)

The requirements for charging flow vary widely according to plant status and configuration. When charging flow is adjusted, the positions of the air-operated valves which control charging flow are adjusted to balance the flows through the charging header and through the seal injection header to ensure that the seal injection flow to the reactor coolant pumps is maintained between 8 and 13 gpm per pump. The reference minimum differential pressure across the seal injection needle valves ensures that regardless of the varied settings of the charging flow control valves that are required to support optimum charging flow, a reference test condition can be established to ensure that flows across the needle valves are within the safety analysis. The values in the safety analysis for this reference set of conditions are calculated based on conditions during power operation and they are correlated to the minimum ECCS flow to be maintained under the most limiting accident conditions.

As noted, the Surveillance is not required to be performed until 8 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 8 hours to ensure that the Surveillance is timely.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.
2. 10 CFR 50.46.
3. Westinghouse Calculation FRSS/SS-GAE-952.

BASES

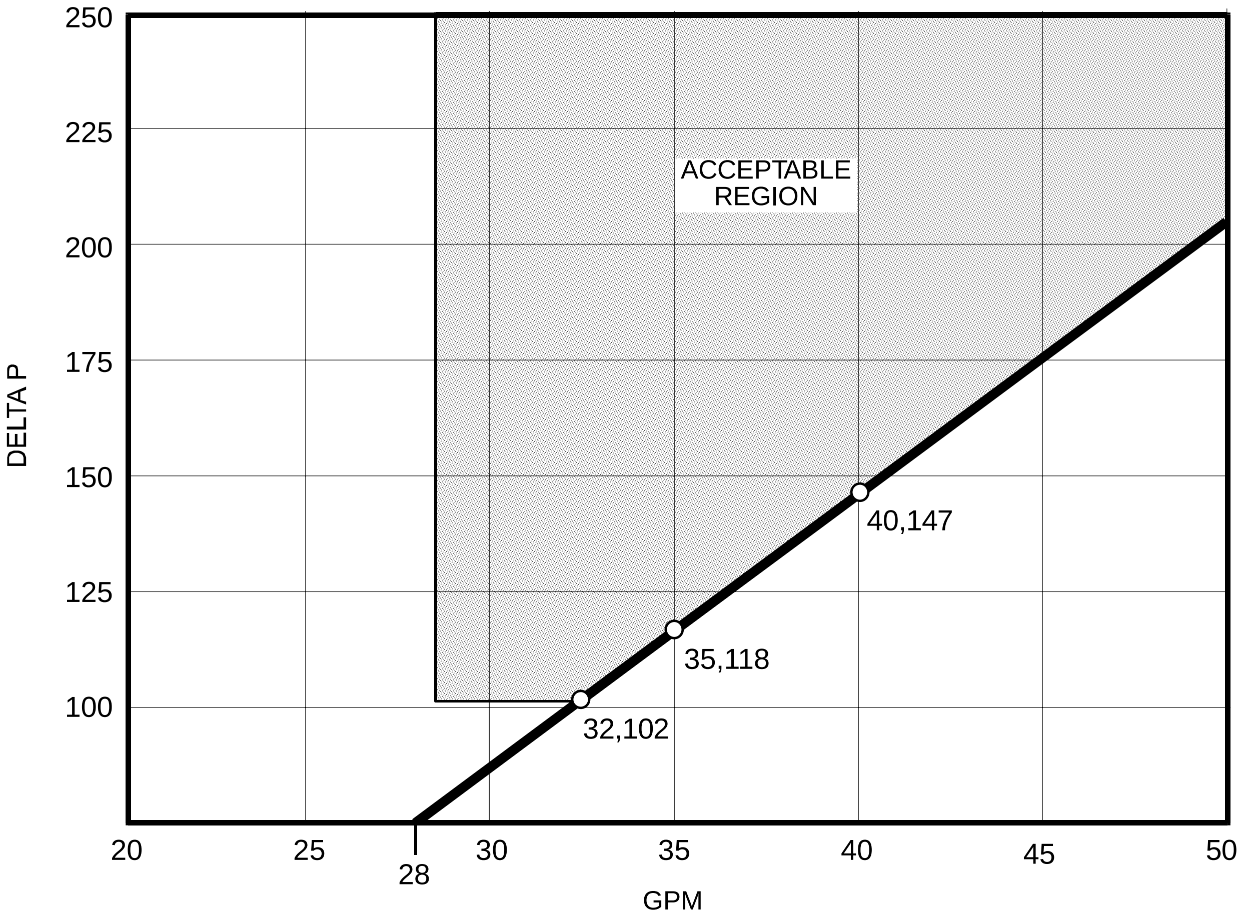

FIGURE B 3.5.5-1
SEAL INJECTION FLOW LIMITS

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.6 Recirculation Fluid pH Control System

BASES

BACKGROUND

The Recirculation Fluid pH Control System is a passive system designed to raise the long term pH of the solution in the containment sump following a Design Basis Accident (DBA). The Recirculation Fluid pH Control System consists of three storage baskets containing crystalline trisodium phosphate (TSP) in the dodecahydrate form ($Na_3PO_4 \bullet 12H_2O \bullet 1/4NaOH$). In the event of a loss of coolant accident (LOCA), the TSP contained in the storage baskets will be dissolved in the reactor coolant system (RCS) and Refueling Water Storage Tank (RWST) inventories lost through the pipe break. The resulting increase in the recirculation solution pH into the range of 7.0 to 10.5 assures that iodine is retained in solution and that chloride induced stress corrosion is minimized (Ref. 1). The Recirculation Fluid pH Control System performs no function during normal plant operation.

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. Fuel damage following a DBA will cause iodine to be released into the reactor coolant and containment atmosphere. Iodine released to the containment atmosphere is absorbed by the containment spray and washed into the containment sump. Since the ECCS water is borated for reactivity control, the recirculation solution in the containment sump will initially be acidic with a pH of approximately 4.5. In a low pH (acidic) solution, some of the dissolved iodine will be converted to a volatile form and evolve out of solution into the containment atmosphere. In order to reduce the potential for elemental iodine evolution, the ECCS recirculation solution is adjusted (buffered) to achieve a long term alkaline pH of no less than 7.0. An alkaline pH promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. In addition to ensuring iodine is retained in solution, an alkaline recirculation solution will minimize chloride induced stress corrosion cracking of austenitic stainless steel ECCS and containment spray components exposed to the high temperature borated water during the recirculation phase of operation after a DBA.

(continued)

BASES

BACKGROUND (continued)

A long term recirculation solution pH of 7.0 to 10.5 also serves to minimize the hydrogen produced by the corrosion of galvanized surfaces and zinc-based paints.

In addition, the determination of this pH range also considered the environmental qualification of equipment in containment that may be subjected to the containment spray.

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution, a total of between 11,484 pounds (220 ft^3) and 14,612 pounds (260 ft^3) of TSP is required. The three TSP storage baskets are designed and located to permit the TSP to be dissolved into the containment recirculation sump solution as the post-LOCA water level rises. The stainless steel mesh screen storage baskets are located in the containment sump area anchored to the filler slab at elevation 171-ft 9-in. The post-LOCA ECCS recirculation and containment spray provide mixing to achieve a uniform solution pH.

TSP, because of its stability when exposed to radiation and elevated temperature and its nontoxic nature, is the preferred buffer material. The dodecahydrate form of TSP is used because of the high humidity in the containment during normal operation. Since the TSP is hydrated, it will not absorb large amounts of water from the humid atmosphere and will be less susceptible to physical and chemical change than the anhydrous form of TSP.

APPLICABLE SAFETY ANALYSES

Following the assumed release of radioactive material from a DBA to the containment atmosphere, the containment is assumed to leak at its design value. The LOCA radiological dose analysis assumes the amount of radioactive material available for release to the outside atmosphere is reduced by the operation of the containment spray system. The analysis also assumes the long term pH control of the recirculation fluid retains the dissolved iodine in solution which prevents the iodine from becoming available for release to the atmosphere (Ref. 2). The radiological consequences of a LOCA may be increased if the long term pH of the recirculation solution is not adjusted to 7.0 or greater. Therefore, long term pH control of the post-LOCA recirculation fluid helps ensure the offsite and control room thyroid doses are within the limits of 10 CFR 100 and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

10 CFR 50, Appendix A, General Design Criterion 19, respectively.

The Recirculation Fluid pH Control System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The OPERABILITY of the Recirculation Fluid pH Control System ensures sufficient TSP is maintained in the three TSP storage baskets to increase the long term recirculation fluid pH to between 7.0 and 10.5 following a LOCA. A pH range of 7.0 to 10.5 is sufficient to prevent significant amounts of iodine released from fuel failure and dissolved in the recirculation fluid, from converting to a volatile form and evolving from solution into the containment atmosphere during the ECCS recirculation phase. In addition, an alkaline pH in this range will minimize chloride induced stress corrosion cracking of austenitic stainless steel components, and minimize the hydrogen produced by the corrosion of galvanized surfaces and zinc-based paints.

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution, a total of between 11,484 pounds (220 ft^3) and 14,612 pounds (260 ft^3) of TSP is required. The required amount of TSP is determined considering the volume of water involved, the target pH range, and the density of different vendor types of TSP that are available. Although the amount of TSP required is based on mass, a required volume is verified since it is not feasible to weigh the entire amount of TSP in containment.

APPLICABILITY

In MODES 1, 2, 3, and 4 a DBA could cause the release of radioactive material in containment requiring the operation of the ECCS Recirculation Fluid pH Control System. The ECCS Recirculation Fluid pH Control System assists in reducing the amount of radioactive material available for release to the outside atmosphere after a DBA.

In MODES 5 and 6, the probability and consequences of an event requiring the ECCS Recirculation Fluid pH control system are reduced due to the pressure and temperature

(continued)

BASES

APPLICABILITY (continued)

limitations in these MODES. Thus, the ECCS Recirculation Fluid pH Control System is not required OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With the ECCS Recirculation Fluid pH Control System inoperable, the system must be restored to OPERABLE status within 72 hours.

The ability to adjust the recirculation fluid pH to the required range and the resulting iodine retention and corrosion protection may be reduced in this condition. The 72 hour Completion Time is based on the passive nature of the system design and the low probability of an event occurring during this time that would require the ECCS Recirculation Fluid pH Control System function.

B.1 and B.2

If the ECCS Recirculation Fluid pH Control System cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 54 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 3). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 3, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 without challenging plant systems. The extended interval to reach MODE 4 allows additional time for restoration of the system and is reasonable considering that the driving force for a release of radioactive material from the RCS is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.5.6.1

In order to achieve the desired pH range of 7.0 to 10.5 in the post-LOCA recirculation solution, a total of between 11,484 pounds (220 ft^3) and 14,612 pounds (260 ft^3) of TSP is required. A visual inspection is performed to verify the structural integrity and content volume of the three TSP storage baskets. The baskets are marked with a minimum and maximum fill level that corresponds to a total TSP volume of between 220 ft^3 and 260 ft^3. The verification that the storage baskets contain the required amount of trisodium phosphate is accomplished by verifying that the TSP level is between the indicated fill marks on the baskets. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.2

2. FSAR, Chapter 15

3. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor 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 Accident (DBA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment consists of a prestressed, posttensioned, reinforced concrete structure with cylindrical walls, hemispherical dome, and base slab lined with welded 1/4-inch carbon steel liner plate, which forms a continuous leaktight membrane.

The cylinder wall is prestressed with a posttensioning system in the vertical and horizontal directions, and the dome roof is prestressed utilizing a three-way post tensioning system.

The concrete reactor building is required for structural integrity of the containment under 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.

The isolation devices for the penetrations in the containment boundary are a part of the containment leaktight barrier. To maintain this leaktight 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

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves," or

3. penetrations required to be closed only in specific accident conditions are capable of being isolated by power operated valves manually operated from the control room in accordance with procedures. An example is the auxiliary component cooling water (ACCW) penetrations.

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks."

c. All equipment hatches are closed and sealed.

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.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break, and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. 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 was designed with an allowable leakage rate of 0.2% of containment air weight per day for the first 24 hours and 0.1% of containment air weight per day thereafter (Ref. 3). This leakage rate (0.2%), used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

L_a is assumed to be 0.2% of containment air weight per day (380,455 sccm) in the safety analysis at P_a = 37 psig (Ref. 3).

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 ≤ $1.0L_a$, 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 equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. FSAR table 6.2.4-1 lists all penetrations and the applicable Appendix J test requirements (Type A, B, or C).

The containment air lock (LCO 3.6.2) leakage rate acceptance criteria are specified in the Containment Leakage Rate Testing Program and the leakage testing requirement for purge valves with resilient seals are specified in LCO 3.6.3. However, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall containment leakage rate acceptance criteria specified in the Containment Leakage Rate Testing Program.

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."

(continued)

BASES (continued)

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.

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. The containment concrete visual examinations may be performed during either power operation, e.g., performed concurrently with other containment inspection-related activities such as tendon testing, or during a maintenance/refueling outage. The visual examinations of the steel liner plate inside containment are performed during maintenance or refueling outages since this is the only time the liner plate is fully accessible.

Failure to meet air lock and purge valve with resilient seal 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. Specific acceptance criteria for as-found and as-left leakage rates, as well as the methods of defining the leakage rates, are contained in the Containment Leakage Rate Testing Program. At all other times between required leakage rate tests, the acceptance criteria are based on an overall Type A leakage limit of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

≤ $1.0L_a$. At ≤ $1.0L_a$ the offsite 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

For ungrouted, post-tensioned tendons, this SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program. Testing and Frequency are in accordance with ASME Boiler and Pressure Vessel Code Section XI, Subsection IWL and applicable addenda as required by 10 CFR 50.55a except where an exemption, relief, or alternative has been authorized by the NRC (Ref. 4).

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. FSAR, Chapter 15.

3. FSAR, Section 6.2.

4. ASME Boiler and Pressure Vessel Code Section XI, Subsection IWL and applicable addenda as required by 10 CFR 50.55a.

5. NEI 94-01, Revision 2-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," dated October 2008.

6. ANSI/ANS-56.8-2002, "American National Standard for Containment System Leakage Testing Requirement."

7. NEI-94-01, Revision 3-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” dated July 2012.

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; one is 9-ft 10-in in diameter and the other is 5-ft 9-in 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 unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The

(continued)

APPLICABLE SAFETY ANALYSES (continued)

containment was designed with an allowable leakage rate of 0.2% of containment air weight per day for the first 24 hours and 0.1% per day thereafter (Ref. 2). This leakage rate is defined as L_a = 0.2% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure P_a = 37 psig following a DBA. This allowable leakage rate (0.2%) forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

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 containment, 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 leaktight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. The pressure and temperature limitations of MODES 5 and 6 reduce the probability and consequences of the events events considered for MODES 1, 2, 3, and 4. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. In MODE 6, the requirements for

(continued)

BASES

APPLICABILITY (continued)

the containment air locks are based on a fuel handling accident inside 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 to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock.

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.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

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 valve 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

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

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.

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. 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

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

perform an allowed activity listed above. 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.

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).

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 door, once it has been verified to be in the proper position, is small.

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, 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

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

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 plant 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 require 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. 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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 3).

D.1 and D.2

If the inoperable containment air lock 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.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

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 applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the overall containment leakage rate.

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.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Section 6.2.
3. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves 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 valves secured in their closed position (including 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. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System. A list of containment isolation valves is provided in FSAR table 6.2.4-2.

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. In addition to the Phase A isolation signal above, the purge and exhaust valves receive a Containment Ventilation isolation signal on a containment high radiation condition. 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). Manual actuations of the Phase A isolation signal are accomplished via either of the two control board handswitches. Manual actuations of the containment ventilation isolation signal are accomplished as a direct result of the manual Phase A isolation actuation or the manual containment spray actuation.

(continued)

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 containment function assumed in the safety analyses will be maintained.

Containment Normal Purge System (24 inch purge valves)
(HV2626A, HV2627A, HV2628A, HV2629A)

The Shutdown Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 24 inch purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 24 inch purge valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Minipurge System (14 inch purge valves)
(HV2626B, HV2627B, HV2628B, HV2629B)

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 for pressure control, ALARA or air quality considerations for personnel entry, or for surveillance or maintenance testing that requires the valves to be open.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a 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 24 inch purge valves are closed at event initiation.

The LOCA offsite dose analysis assumes, as an initial condition, isolation of all containment penetrations, with the exception of the 14 inch mini-purge. The mini-purge is the only penetration whose flow rate and isolation time are explicitly modeled in the dose analysis, since it provides a direct activity release path from the containment to the environment. It is currently assumed to isolate within 5 seconds of receiving a containment isolation signal (8.5 seconds from event initiation). Following isolation of the purge, the containment is assumed to leak at the design leak rate L_a.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the 14 inch containment purge valves. Two valves in series on each 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 14 inch line are provided with diverse power sources (buses A and B of the Class 1E power system) and pneumatically operated spring closed valves that will fail closed on the loss of power or air.

The 24 inch purge valves may be unable to close in the environment following a LOCA. Therefore, each of the 24 inch purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. The requirement to seal close the 24 inch purge valves precludes a single failure from

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 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 power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 24 inch purge valves must be maintained sealed closed. The valves covered by this LCO are listed along with their associated stroke times in the FSAR (Ref. 2).

The normally closed containment isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, and blind flanges are in place.

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. This LCO is applicable to those containment isolation valves listed in FSAR table 6.3.4-2 unless otherwise noted.

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.

(continued)

BASES

APPLICABILITY (continued)

Therefore, the containment isolation valves 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."

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 24 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 single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.3.1.

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 acceptance criteria, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

In the event one containment isolation valve 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 containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. 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. 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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 4).

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 that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days 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.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these valves 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 securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, 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 valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. 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 that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

CONDITION B is modified by two Notes. The first Note states it is not applicable when the second containment isolation valve is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action for two containment isolation valves inoperable is only intended when the second containment isolation valve is found inoperable and the first valve in the line is already

(continued)

BASES

ACTIONS

B.1 (continued)

inoperable, or when both valves are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 4).

C.1, C.2, and C.3

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, or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, or blind flange. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

In accordance with Required Action C.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are 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 valve manipulation. Rather, it involves verification that those isolation devices outside containment capable of being mispositioned are in the correct position. 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.

Required Action C.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

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

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 securing components is to ensure that these devices are not inadvertently repositioned.

Condition C is modified by two Notes. The first Note states it is not applicable when the second containment purge valve is intentionally made inoperable. The Required Action for two containment purge valves inoperable is not intended for voluntary removal of redundant systems or components from service. The Required Action is only intended if the second containment purge valve is found inoperable and the first purge valve in the line is already inoperable or if both containment purge valves were found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 4).

D.1 and D.2

If the Required Actions and associated Completion Times are not met, 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1
(HV-2626A, HV-2627A, HV-2628A, HV-2629A)

Each 24 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)
(HV-2626A, HV-2627A, HV-2628A, HV-2629A)

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. In this application, the term "sealed" has no connotation of leak tightness. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.3.2
(HV-2626B, HV-2627B, HV-2628B, HV-2629B)

This SR ensures that the minipurge valves are closed as required or, if open, open for an allowable reason. 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 14 inch containment purge supply and exhaust isolation valves may be opened under conditions delineated in administrative procedures. These procedures specify those circumstances under which it is acceptable to open the valves; for example, pressure control, establishment of respirable air quality prior to containment entry, maintenance, or surveillance testing.

The procedures specify that: (1) the valves must be capable of closing under accident conditions, (2) that the instrumentation for causing isolation of the valves is functioning, and (3) the effluent release will be monitored and that it will be within regulatory limits. 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.

SR 3.6.3.3

This SR requires verification that each containment isolation 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

require any testing or valve manipulation. Rather, it involves verification 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.

SR 3.6.3.4

This SR requires verification that each containment isolation 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 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4 (continued)

Note 1 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.

Note 2 modifies the requirement to verify the blind flange on the fuel transfer canal. This blind flange is only required to be verified closed after the completion of refueling activities when the flange has been replaced for MODE 4 entry and no more fuel transfers between the fuel handling building and containment will occur. The flange is only removed to support refueling operations and once replaced is not removed again until the next refueling. Since the removal of this flange is limited to refueling operations, and access to it is restricted during MODES 1, 2, 3, and 4, the probability of it being mispositioned between refuelings is small. Therefore, it is reasonable that it be verified once upon completion of refueling activities prior to entering MODE 4 from MODE 5.

SR 3.6.3.5

Verifying that the isolation time of each automatic power-operated 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 isolation time and Frequency of this SR are in accordance with the INSERVICE TESTING PROGRAM. Any change in the scope or frequency of this SR requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

SR 3.6.3.6

Leak rate testing of the purge supply and exhaust valves with resilient seals is required to be performed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.7

Automatic containment isolation valves close on a containment Phase A or containment ventilation 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 Phase A or containment ventilation 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.

REFERENCES

1. FSAR, Chapter 15.
2. FSAR, Section 6.2.
3. STI Evaluation 417332.
4. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

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 pressure transients. The SLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 17.7 psia (3.0 psig). This resulted in a maximum peak pressure from a SLB of 36.5 psig. The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure during a LOCA, P_a, is less than 36.5 psig. The maximum containment pressure resulting from the worst case SLB, 36.5 psig, does not exceed the containment design pressure, 52 psig.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment was also designed for an external pressure load equivalent to -3 psig. 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 14.093 psia. This resulted in a minimum pressure inside containment of 11.77 psia, 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. 2).

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

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 ensures 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

(continued)

BASES

APPLICABILITY (continued)	limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

ACTIONS

A.1

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.

B.1 and B.2

If containment pressure cannot be restored to within limits 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1
(PI-0934, PI-0935, PI-0936, PI-0937, P-9871, PI-10945)

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.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.2.
2. 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 that establishes 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).

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 303.1°F. The design temperature is 381°F. The design temperature was used in calculating the thermal gradients across the containment wall.

The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature (following an MSLB) was calculated to be less than the containment design temperature. Equipment qualification (Ref. 2) takes into account the most severe environmental conditions including the calculated peak transient temperature following an MSLB (303.1°F).

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).

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 SLB. 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).

(continued)

BASES (continued)

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 containment design temperature. 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 MODE 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.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Location	Tag Number
a. Level 2	TE-2563
b. Level B	TE-2613
c. Level C	TE-2612

NOTE: A local sample may be taken at a corresponding location in lieu of using one of the instruments designated above.

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 representative sample of the overall containment atmosphere. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 6.2.

2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems (Atmospheric and Dual)

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 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. 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 limits and maintains post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains of equal capacity, 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).

(continued)

BASES

BACKGROUND

Containment Spray System (continued)

The Containment Spray System provides a spray of cold borated water 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 coolers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

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 empty tank level alarm is received (8% level). When the RWST level reaches the empty tank level, 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 of four fan units is supplied with cooling water from a separate train of nuclear service cooling water (NSCW). Air is drawn into the coolers through the fan and discharged to the steam generator compartments, pressurizer compartment, and instrument tunnel, and outside the secondary shield in the lower areas of containment.

(continued)

BASES

BACKGROUND

Containment Cooling System (continued)

During normal operation, four fan units are operating. The fans are normally operated at high speed with NSCW supplied to the cooling coils. The Containment Cooling System, operating in conjunction with the Containment Ventilation and Air Conditioning systems, 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 motor overload from the higher mass atmosphere. The temperature of the NSCW 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 loss of coolant accident (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.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 36.5 psig (experienced during a SLB). The analysis shows that the peak containment temperature is 303.1°F (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4A, "Containment Pressure," and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.6.5A for a detailed discussion.) The analyses and evaluations assume a unit specific power level of 100%, one containment spray train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 3 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. 2).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation results in an 11.77 psia 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 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 94 seconds includes diesel generator (DG) startup (for loss of offsite power), block loading of equipment, containment spray pump startup, and spray line filling. Because the total response time required to develop spray flow cannot be measured in practice, the total response time includes an allotment of 55 seconds for spray line filling (Ref. 3).

Containment cooling train performance for post accident conditions is given in Reference 4. 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 4.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-1 pressure setpoint to achieving full Containment Cooling System air and safety grade cooling water flow. The Containment Cooling System fan response time of 48 seconds includes signal delay and DG startup (for loss of offsite power) (Ref. 3).

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. 4). 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. 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 typically 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.

Each Containment Cooling System typically includes demisters, 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.

(continued)

BASES

APPLICABILITY (continued)

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 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour 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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 9).

B.1

With one of the required containment cooling trains inoperable, the inoperable required containment cooling train must be restored to OPERABLE status within 72 hours. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, 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 (Ref. 9).

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable containment spray or cooling train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions in an orderly manner and without challenging plant systems.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1 (continued)

SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment (only check valves are inside containment) and capable of potentially being mispositioned are in the correct position.

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 an individual who can rapidly close the system vent flow path if directed.

SR 3.6.6.2

Operating each pair of containment cooling fan units for ≥ 15 minutes ensures that all fan units are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage or fan or motor failure can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.3

Verifying that the NSCW flow rate to each pair of units (FI-1818A & B and FI-1819A & B) is ≥ 1359 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 4). 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 OM Code (Ref. 6). 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 testing confirms component

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.4 (continued)

OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the INSERVICE TESTING PROGRAM.

In addition to the acceptance criteria of the INSERVICE TESTING PROGRAM, performance of this SR also verifies that pump performance is greater than or equal to the performance assumed in the safety analysis.

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. Any change in the scope or frequency of SR 3.6.6.6 requires reevaluation of STI Evaluation number 417332, in accordance with 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 and operates at low speed. 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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, 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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.9 (continued)

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. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.
2. 10 CFR 50, Appendix K.
3. FSAR, Chapter 7.
4. FSAR, Section 6.2.
5. Not used.
6. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
7. STI Evaluation 417332.
8. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.
9. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Containment Sump

BASES

BACKGROUND

The containment sumps provide a borated water source to support recirculation of coolant from the containment sumps for residual heat removal, emergency core cooling, containment cooling, and containment atmosphere cleanup during accident conditions.

The containment sumps supply both trains of the Emergency Core Cooling System (ECCS) and the Containment Spray System (CSS) during any accident that requires recirculation of coolant from the containment sumps. The recirculation mode is initiated when the pump suction is transferred to the containment sumps on low Refueling Water Storage Tank (RWST) level, which ensures the containment sumps have enough water to supply the net positive suction head to the ECCS and the CSS pumps. There are four containment sumps with two sumps providing suction for the two independent ECCS trains and two sumps providing suction for the two independent CSS trains.

The containment sumps 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, CSS 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 sump water source could result in insufficient recirculation of coolant during the accident, or insufficient heat removal from the core during the accident.

APPLICABLE SAFETY ANALYSES

During all accidents that require recirculation, the containment sumps provide a source of borated water to the ECCS and CSS pumps. As containment cooling, and containment atmosphere cleanup during an accident. It 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.”

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

FSAR Appendix 6A (Ref. 2) describes evaluations that confirm long-term core cooling is assured following any accident that requires recirculation from the containment sump.

The containment sumps satisfy Criterion 3 of 10CFR 50.36(c)(2)(ii).

LCO

Four containment sumps are required to ensure a source of borated water to support ECCS and CSS OPERABILITY. A containment sump consists of the containment drainage flow paths, the associated containment sump strainer, and the inlet to the ECCS or CSS piping. An OPERABLE containment sump has no structural damage or not be restricted by containment accident generated and transported debris.

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 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 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 sump pool or are generated withing containment and transported to the containment sump.

Containment debris limits are defined in Table B 3.6.7-1 and additional discussion is provided in FSAR Appendix 6A (Ref. 2)

(continued)

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, containment sump OPERABILITY requirements are dictated by the ECCS and CSS OPERABILITY requirements. Since both, the ECCS and the CSS must be OPERABLE in MODES 1, 2, 3, and 4, the containment sumps must also be OPERABLE to support their operation.

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 defined in Table B 3.6.7-1 and additional discussion is provided in FSAR Appendix 6A (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 cold e indicative of an increased potential for an RCS pipe break, which could result in debris being generated and transported to the containment sump. The more frequent monitoring allows operators to act in a timely fashion to minimize the potential for an RCS pipe break while the containment sump is inoperable.

(continued)

BASES

ACTIONS (continued)

For the purposes of applying LCO 3.0.6 and the Safety Function Determination Program while in Condition A, the four containment sumps are considered a single support system for all ECCS and CSS trains because containment accident generated and transported debris issues that would render one sump inoperable would render all of the sumps inoperable.

The inoperable containment sump 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 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.

<u>B.1</u>

When one or more containment sumps are inoperable for reasons other than Condition A, such as blockage, structural damage, or abnormal corrosion that could prevent recirculation of coolant, the affected ECCS and CSS trains are rendered inoperable; therefore, the affected ECCS and CSS trains must be immediately declared inoperable. Declaring the affected trains inoperable ensure appropriate restrictions are implemented in accordance with the Required Actions of the ECCS and CSS Specifications.

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

If the containment sump cannot be restored to OPERABLE status within the associated Completion Time for Condition A, the plant must be brough to a MODE in which the LCO does not apply. To achieve this status, the plant must be brough tot 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.7.1 Periodic inspections are performed to verify the containment sumps do not show current or potential debris blockage, structural damage, or abnormal corrosion to ensure the operability and structural integrity of the containment sumps. (Ref. 1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. FSAR, Chapter 6 and Chapter 15. 2. FSAR Appendix 6A, Resolution of NRC Generic Letter 2004-02.

Table B 3.6.7-1 (page 1 of 1)
Containment Sump Debris Limits Applicable to Breaks ≤ 6 inches for 1 Train Operation and to Breaks ≤ 10 inches for 2 Train Operation

Debris Type	Acceptable Limit
Insulation Fiber Debris*	95.2 ft^3
Qualified and Unqualified Coatings Debris*	16.8 ft^3
Fire Barrier Debris*	284.7 lb_m
Latent Debris**	200 lb_m
Miscellaneous Debris (Tags, Labels, etc.) **	50 ft^2

* Acceptable quality of debris on one RHR strainer

** Total quantity of debris in containment, which would predominately transport to the active RHR strainer for single train operation and split proportionally for two train operation.

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.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the FSAR, Section 10.3 (Ref. 1). The actual MSSV capacity is 114% of rated steam flow at 110% of the steam generator design pressure. This meets 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 requirement is that secondary system pressure is limited to 110% of design pressure which is specified in Reference 2. The actual design basis applied for the MSSVs comes from Reference 6 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure when passing 105% of design steam flow. This design basis is sufficient to cope with any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in the FSAR, Section 15.2 (Ref. 3). Of these, the full power turbine trip without steam dump is the limiting AOO. This event also terminates normal feedwater flow to the steam generators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The transient response for turbine trip without a direct reactor trip from full power with all MSSVs OPERABLE presents no hazard to the integrity of the RCS or the Main Steam System. If a minimum reactivity feedback is assumed, the reactor is tripped on high pressurizer pressure. In this case, the pressurizer safety valves open, and RCS pressure remains below 110% of the design value. The MSSVs also open to limit the secondary steam pressure.

If maximum reactivity feedback is assumed, the reactor is tripped on overtemperature ΔT. The departure from nucleate boiling ratio increases throughout the transient, and never drops below its initial value. Pressurizer relief valves and MSSVs are activated and prevent overpressurization in the primary and secondary systems. 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.

Operation with one or more MSSVs inoperable is permitted at the reduced power levels specified in Table 3.7.1-1. If the power levels specified in Table 3.7.1-1 are exceeded, the OPERABLE MSSVs may not have sufficient capacity to preclude primary and/or secondary overpressurization. The reduced power levels specified in Table 3.7.1-1 may be exceeded during a turbine trip/loss of load transient due to the effect of a positive Moderator Temperature Coefficient. With a positive Moderator Temperature Coefficient, the applicable safety analysis for the turbine trip/loss of load event (Ref. 4) takes credit for the reduced Neutron Flux High Trip Setpoint to terminate the event and prevent primary and secondary overpressurization.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at full power. An MSSV will be considered inoperable if it fails to open on demand. The LCO requires that five MSSVs be OPERABLE in compliance with Reference 2 and the DBA analysis. This is because operation with less than the full number of MSSVs requires limitations

(continued)

BASES

LCO (continued)

on allowable THERMAL POWER (to meet ASME Code requirements and the DBA analysis). These limitations are according to Table 3.7.1-1 in the accompanying LCO, and Required Action A.1.

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic lift setpoint testing in accordance with the INSERVICE TESTING PROGRAM.

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 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.

APPLICABILITY

In MODE 1 above 31% RTP, the number of MSSVs per steam generator required to be OPERABLE must be according to Table 3.7.1-1 in the accompanying LCO. Below 31% RTP in MODES 1, 2, and 3, only two MSSVs per steam generator are required to be OPERABLE.

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, reduce power so that the available MSSV relieving capacity meets Reference 2 requirements for the applicable THERMAL POWER.

(continued)

ACTIONS

A.1 and A.2 (continued)

In addition to reducing power within 4 hours, the requirement to reduce the Power Range Neutron Flux-High Trip Setpoint (NI-0041, NI-0042, NI-0043 and NI-0044) in 12 hours is necessary to limit operation to the power levels specified in Table 3.7.1-1 and ensure a timely reactor trip in the event of a turbine trip/loss of load transient. If the power levels specified in Table 3.7.1-1 are exceeded, the OPERABLE MSSVs may not have sufficient capacity to preclude primary and/or secondary overpressurization. The reduced power levels specified in Table 3.7.1-1 may be exceeded during a turbine trip/loss of load transient due to the effect of a positive Moderator Temperature Coefficient. With a positive Moderator Temperature Coefficient, the applicable safety analysis for the turbine trip/loss of load event takes credit for the reduced Neutron Flux-High Trip Setpoint to terminate the event and prevent primary and secondary overpressurization. The allowed Completion Times to reduce power and reduce the Power Range Neutron Flux-High trip setpoint are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to less than the heat removal 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. For example, if one MSSV is inoperable in one steam generator, the relief capacity of that steam generator is reduced by approximately 29%. To offset this reduction in relief capacity, energy transfer to that steam generator must be similarly reduced by at least 29%. This is accomplished by reducing THERMAL POWER by at least 29%, which conservatively limits the energy transfer to all steam generators to approximately 71% of total capacity, consistent with the relief capacity of the most limiting steam generator.

The maximum power level specified for the Power Range Neutron Flux-High Trip Setpoint with inoperable MSSVs must ensure that power is limited to less than the heat removal capacity of the remaining OPERABLE MSSVs. With a positive

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

moderator temperature coefficient, the reduced high flux trip setpoint also ensures that the reactor trip occurs early enough in the loss of load/turbine trip event to limit primary to secondary heat transfer and preclude overpressurization of the primary and secondary systems.

B.1 and B.2

If the reactor power or the Power Range Neutron Flux-High Trip Setpoints cannot be reduced as required in Table 3.7.1-1 within the associated Completion Time, or if one or more steam generators have four or more MSSVs inoperable per steam generator, 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 and applicable ASME OM Code (Ref. 5) requirements. The ASME OM Code specifies the necessary test activities and test intervals. As a minimum, the testing will include:

a. Verification of the lift setpoint for each valve at an interval not greater than once every 5 years; and

b. If the valve is removed for lift setpoint testing, a valve seat leakage test will be performed to verify compliance with the owner's acceptance criteria.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

Table 3.7.1-2 allows a + 2%/ - 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

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. FSAR, Section 10.3.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.
3. FSAR, Section 15.2.
4. Westinghouse Letter GP-19899, “Transmittal of LTR-TA-20-163 Revision 0, ‘Vogtle Units 1 and 2: Safety Analysis Supporting Operation with Inoperable MSSVs,’” December 2020.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
6. Westinghouse Steam System Design Manual, SIP/10-1, Revision 3, March 1978.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIV systems isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV system closure terminates flow from the unaffected (intact) steam generators.

The MSIV system consists of an MSIV and associated bypass valve. Two MSIV systems are located in series in each main steam line outside, but close to, containment. The MSIV systems are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV system closure. Closing the MSIV systems 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 systems close on a main steam isolation signal which can be generated by low steam line pressure, steam line pressure negative rate high, or high containment pressure. The MSIVs fail closed on loss of control or actuation power. The MSIVs may also be actuated manually.

Each MSIV has an MSIV bypass isolation valve. The bypass valves are normally open and receive the same emergency closure signal as do their associated MSIVs. The bypass valves are normally left open to minimize condensation buildup in the bypass lines. The bypass valves may be manually closed. An OPERABLE MSIV system may consist of an OPERABLE MSIV and an inoperable associated bypass valve provided the inoperable bypass valve is maintained closed.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in FSAR, Section 6.2 (Ref. 2).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

It is also established by the analysis of the SLB core response events presented in FSAR Subsections 15.1.5 (Ref. 3) and 15.4.9 (Ref. 4) and by the analysis of the feedline break event presented in FSAR Subsection 15.2.8 (Ref. 5). The design basis of the MSIVs serves only a safety function which is to preclude 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), for any of the postulated events listed above. Closure of the MSIVs isolates the break (either SLB or feedline) from the unaffected steam generators. The MSIVs normally remain open during power operation.

Because of the redundant design, i.e., two MSIVs per steam line, multiple failures would have to occur in order for more than one steam generator to blow down during an SLB or feedline break event. Thus, the single failure of an MSIV will not result in a more limiting transient for any of the SLB or feedline break events. The closure of the MSIVs occurs on either a low steam line pressure signal, a steam line pressure negative rate - high signal, a high - high containment pressure signal, or manually, isolating the break from the unaffected steam generators.

The MSIVs operate under the following situations:

a. For any SLB inside containment, steam is discharged into containment from all steam generators until the MSIVs close. After MSIV closure, steam is discharged into containment from only the affected steam generator. Closure of the MSIVs isolates the break from the unaffected steam generators. This is also true for the feedline break event in which feedwater from the faulted steam generator is discharged to containment.

b. An SLB outside containment and upstream from the MSIVs is not a containment pressurization concern. It is a concern with respect to offsite dose, although a break in this short section of piping has a very low probability. A break upstream of the MSIV is limiting with respect to the core response. SLBs from full power and zero power conditions are analyzed to demonstrate that the applicable acceptance criteria are satisfied. A break in this location is also

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

limiting with respect to the steam releases used in meeting equipment qualification criteria. The failure of an MSIV has no effect on the results of these events.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs. This is not a limiting scenario with respect to doses or with respect to the core response analyses.

d. For a steam generator tube rupture, closure of the MSIVs in the faulted loop isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

This LCO requires that two MSIV systems in each steam line be OPERABLE. The MSIV systems are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal. An OPERABLE MSIV system may consist of an OPERABLE MSIV and inoperable associated bypass valve provided the inoperable bypass valve is maintained closed.

This LCO provides assurance that the MSIV systems will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 6) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIV systems must be OPERABLE in MODE 1, and in MODES 2 and 3 except when one MSIV system in each steam line is closed, when there is significant mass and energy in the RCS and steam generators. When the MSIV systems are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIV systems are closed, and the steam generator energy is low.

(continued)

BASES

APPLICABILITY (continued)

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

---------------------------------------NOTE---
A Note has been added to the ACTIONS to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each steam line. The Completion Time(s) of the inoperable MSIV systems will be tracked separately for each steam line starting from the time the Condition was entered for that steam line.

A.1

With one MSIV system inoperable in one or more steam lines in MODE 1, action must be taken to restore the MSIV system to OPERABLE status within 72 hours. Some repairs to the MSIV can be made with the unit at power. The 72 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 and the remaining OPERABLE MSIV system in the steam line. This Completion Time is consistent with other ESF systems that contain redundant trains of equipment. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 8).

B.1

With two MSIV systems inoperable in one or more steam lines in MODE 1, action must be taken to restore one MSIV system to OPERABLE status in the affected steam line(s) within 4 hours. In this condition, the affected steam line has no OPERABLE automatic isolation capability. The 4 hour Completion Time allows for minor repair or trouble shooting that may prevent a unit shutdown to MODE 2 and is reasonable considering the low probability of an accident occurring during this time period that would require a closure of the MSIV systems and the reduction in potential for a plant transient (shutdown to MODE 2) provided by the 4 hours allowed for repairs. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 8).

(continued)

BASES

ACTIONS

B.1 (continued)

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second MSIV in one steam line is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only intended if the second MSIV in one steam line is found inoperable with one MSIV already inoperable, or if both MSIVs in one steam line are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, "Risk Informed Completion Time Program", which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref 8).

C.1

If the MSIV system cannot be restored to OPERABLE status within the stated Completion Time, the unit must be placed in a MODE in which the ACTIONS provide the option to close the inoperable MSIV system and thus accomplish the system's safety function. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition D or E entered. The Completion Time is reasonable, based on operating experience, to reach MODE 2 in an orderly manner without challenging unit systems.

D.1

Required Action D.1 applies when one or more steam lines have a single inoperable MSIV system in MODE 2 or 3.

Since the MSIV systems are required to be OPERABLE in MODES 2 and 3, the inoperable MSIV system may either be restored to OPERABLE status or the affected steam line isolated by closing one MSIV system in that line. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 7 day Completion Time is reasonable considering the remaining OPERABLE redundant MSIV system in each affected steam line.

(continued)

BASES

ACTIONS

D.1 (continued)

For inoperable MSIV systems that cannot be restored to OPERABLE status within the specified Completion Time, and the steam line is isolated by a closed MSIV system, the MSIV systems 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 system status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

E.1

With two MSIV systems inoperable in one or more steam lines in MODE 2 or 3, action must be taken to restore one MSIV system to OPERABLE status or verify one MSIV system closed in the affected steam line(s) within 4 hours. In this condition, the affected steam line has no OPERABLE automatic isolation capability. Verifying one MSIV system closed ensures the safety function is accomplished for that steam line. The 4 hour Completion Time is reasonable considering the low probability of an accident occurring during this time period that would require a closure of the MSIV systems.

For inoperable MSIV systems that cannot be restored to OPERABLE status and are closed, the MSIV system must be verified closed on a periodic basis. Verification of MSIV system closure on a periodic basis 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 system indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

F.1 and F.2

If the MSIV systems 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 unit systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that the closure time of each MSIV system is within the limit given in Reference 9 on an actual or simulated actuation signal and is within that assumed in the accident and containment analyses. This SR also verifies the valve closure time is in accordance with the INSERVICE TESTING PROGRAM. This SR is normally performed upon returning the unit to operation following a refueling outage.

The Frequency is in accordance with the INSERVICE TESTING PROGRAM. Operating experience has shown that these components usually pass the Surveillance when performed in accordance with the INSERVICE TESTING PROGRAM. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. If desired, this allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. FSAR, Section 10.3.
2. FSAR, Section 6.2.
3. FSAR, Subsection 15.1.5.
4. FSAR, Subsection 15.4.9.
5. FSAR, Subsection 15.2.8.
6. 10 CFR 100.11.
7. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
8. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).
9. TRM, Section 13.7.6.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulation Valves (MFRVs) and Associated Bypass Valves

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs and associated bypass valves or MFRVs and associated bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs or MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs and associated bypass valves, or MFRVs and associated bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs and associated bypass valves, or MFRVs and associated bypass valves, isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV and associated bypass valve, and one MFRV and its associated bypass valve, are located on each MFW line, outside but close to containment. The MFIVs and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

(continued)

BASES

BACKGROUND (continued)	The MFIVs and associated bypass valves, and MFRVs and associated bypass valves, close on receipt of a T_{avg} – Low coincident with reactor trip (P-4), steam generator water level – high high, or SI signal. They may also be actuated manually. In addition to the MFIVs and associated bypass valves, and the MFRVs and associated bypass valves, a check valve is available. The check valve isolates the feedwater line, penetrating containment, and ensures that the consequences of events do not exceed the capacity of the containment heat removal systems. A description of the MFIVs and MFRVs is found in the FSAR, Subsection 10.4.7 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the MFIVs and MFRVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs and associated bypass valves, or MFRVs and associated bypass valves, may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level – high high signal or a feedwater isolation signal on high steam generator level. Failure of an MFIV, MFRV, or the associated bypass valves to close following an SLB or FWLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event. The MFIVs and MFRVs satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
LCO	This LCO ensures that the MFIVs, MFRVs, and their associated bypass valves will isolate MFW flow to the steam generators, following an FWLB or main steam line break. These valves will also isolate the nonsafety related portions from the safety related portions of the system.

(continued)

BASES

LCO (continued)

This LCO requires that four MFIVs and associated bypass valves and four MFRVs and associated bypass valves be OPERABLE. The MFIVs are provided with dual pneumatic/hydraulic power trains each receiving a feedwater isolation signal from separate ESFAS actuation logic trains. Actuation of either pneumatic/hydraulic power train will cause the MFIVs to close. The MFRVs are equipped with dual solenoids to actuate the valve on a feedwater isolation signal. Each solenoid gets an actuation signal from separate ESFAS actuation logic trains. The solenoid logic for the MFRVs requires both solenoids to actuate for the MFRVs to isolate. The redundancy built into the MFIV closure system prevents any single failure other than a mechanical failure of the valve itself from preventing the MFIV from performing its design function. If a mechanical failure of an MFIV does occur, it becomes the assumed single failure, and the MFRVs would be assumed to perform their isolation function. If an MFRV fails to actuate due to a mechanical failure of the valve itself, or a failure of one train of actuation logic, this becomes the assumed single failure, and the MFIVs would be assumed to perform their isolation function. The MFIVs and MFRVs and the associated bypass valves are considered OPERABLE when isolation times are within limits and capable of closing on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. If a feedwater isolation signal on high steam generator level occurs due to an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIVs and MFRVs and the associated bypass valves must be OPERABLE whenever there is significant energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1 and 2, the MFIVs and MFRVs and the associated bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 3, 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, and the associated bypass valves are normally closed since MFW is not required.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, the required safety function is being performed.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. 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 valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, the required safety function is being performed.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. 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 valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one associated bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, the required safety function is being performed.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable associated bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. 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 valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

D.1

With the combination of inoperable MFIVs, MFRVs, and bypass valves such that a feedwater line has no OPERABLE isolation system, action must be taken to restore one of the redundant isolation systems to OPERABLE status or isolate the affected feedwater line within 8 hours. With one isolation system restored to OPERABLE status, operation may continue with any remaining inoperable valves being addressed by the appropriate Condition(s) (A, B, and/or C) of this LCO. With the affected feedwater line isolated, the safety function of the isolation system is accomplished and power operation is limited accordingly. The Completion Time is reasonable considering the low probability of an event occurring that would require feedwater isolation during this time, and that in most cases, the only action necessary for system restoration would be to close and deactivate a valve.

(continued)

BASES

ACTIONS

D.1 (continued)

The term isolation system as used in this Condition consists of an MFIV and associated bypass valve or an MFRV and associated bypass valve. An OPERABLE system may include inoperable valve(s) provided the inoperable valves are closed and deactivated. This is acceptable since the closed isolation valve(s) are performing their intended safety function. Since the MODE of Applicability excepts valves that are closed and deactivated, the LCO is no longer applicable to those valves.

E.1 and E.2

If the MFIV(s) and MFRV(s) and the associated bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated 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. The allowed Completion Time is 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 3.7.3.1

This SR verifies that the closure time of each MFIV, MFRV, and associated bypass valves is within the limit given in Reference 3 on an actual or simulated actuation signal and is within that assumed in the accident and containment analyses. This SR also verifies the valve closure time is in accordance with the INSERVICE TESTING PROGRAM. This SR is normally performed upon returning the unit to operation following a refueling outage.

This SR is modified by a Note that allows entry into and operation in MODE 2 prior to performing the SR.

The Frequency for this SR is in accordance with the INSERVICE TESTING PROGRAM. Operating experience has shown that these components usually pass the Surveillance when performed in accordance with the INSERVICE TESTING PROGRAM.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Subsection 10.4.7.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
3. TRM, Section 13.7.7.

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Relief Valves (ARVs)

BASES

BACKGROUND

The ARVs 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 FSAR, 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 ARVs 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.

One ARV line for each of the four steam generators is provided. Each ARV line consists of one ARV and an associated block valve.

The ARVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ARVs are equipped with electrohydraulic actuators to permit control of the cooldown rate.

Each ARV is provided with a pressurized gas (nitrogen) accumulator. The accumulator is sized to provide sufficient hydraulic power to operate the ARVs for one full stroke.

A description of the ARVs is found in Reference 1. The ARVs are powered from Class 1E sources. In addition, hand pumps are provided for local manual operation.

APPLICABLE SAFETY ANALYSES

The ARVs provide an alternate method for cooling the unit to RHR entry conditions whenever the preferred heat sink via the steam dumps to the condenser is unavailable. The limiting design basis for the ARVs is established by the Steam Generator Tube Rupture (SGTR) event, FSAR, Subsection 15.6.3 (Ref. 2). The SGTR event is analyzed to determine that the offsite radiological doses remain less than the guideline values. The SGTR event assumes a coincident loss of offsite power, which is conservative with respect to the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

offsite radiological doses, and a most limiting single failure. The loss of offsite power assumption results in the ARVs being relied on to reduce RCS temperature to recover from an SGTR and also to reduce RCS temperature and pressure to RHR entry conditions. In addition, the SGTR analysis considers SG overfill. SG overfill during an SGTR event is a concern due to the potential liquid release via the ARV or Main Steam Safety Valves (MSSVs) to the atmosphere that must be assumed and the resulting increase in the offsite radiological dose. The limiting single failure with respect to SG overfill is the failure of one ARV on an intact SG to open when required for cooldown of the RCS. The analysis assumes three ARVs are OPERABLE at the start of the event. One of the ARVs is on the ruptured SG, another ARV is assumed to fail to open, and the remaining ARV is used to perform the RCS cooldown. However, there is also a scenario where the limiting single failure is the loss of control power for the two remaining ARVs. In this case, the ARVs cannot be controlled from the control room to initiate cooldown. The ARVs are equipped with local handpumps that can be used to manually open them. Given a tube rupture on one of the steam generators with an operable ARV, and the limiting single failure being a loss of control power to the remaining operable ARVs, only one ARV must be capable of being manually actuated using its handpump. If the ARV on the ruptured generator also has one of the functional handpumps, then only one of the remaining ARVs need have a functional handpump in order to meet the safety analysis. Because no additional failures need to be postulated in addition to the loss of control power, only two functional ARV handpumps are required. The analysis shows that cooldown using a single ARV does not result in SG overfill. The failure of one ARV to open does not represent the most limiting single failure with respect to offsite radiological doses. The failure open of the ARV on the ruptured SG is the limiting failure for offsite radiological doses. This failure results in an uncontrolled depressurization of the ruptured SG until the local manual isolation valve for that ARV is closed. This failure maximizes the activity release from the ruptured SG to the atmosphere.

The recovery from the SGTR requires a rapid cooldown to establish adequate subcooling as a necessary step to allow depressurization of the RCS to terminate the primary to secondary break flow in the ruptured steam generator. The time required to terminate the primary to secondary break flow in the SGTR event is more critical than the time required to cool the RCS down to RHR conditions for this

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

event and other accident analyses. After primary to secondary break flow termination, it is assumed that one ARV on an intact SG is used to cool the RCS down to 350°F, at the maximum allowable cooldown rate of 100°F/hour.

The offsite radiological dose analyses show that the failure open of the ARV on the ruptured SG represents the limiting single failure. The resulting offsite radiological doses at the exclusion area boundary, low population zone, and control room are well within the allowable guidelines as specified by Standard Review Plan 15.6.3 and 10 CFR 100. A detailed description of the SGTR analyses can be found in WCAP-11731 and associated supplements (Ref. 3).

The ARVs are equipped with manual block valves in the event an ARV spuriously fails open or fails to close during use.

The ARVs satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Three ARV lines are required to be OPERABLE. One ARV line is required from each of three steam generators to ensure that at least one ARV line is 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 ARV line on an unaffected steam generator. A block valve for each required ARV must be OPERABLE to isolate a failed open ARV line.

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.

An ARV 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. Additionally, it is required that at least two of the three OPERABLE ARVs maintain the capability for local manual actuation via their associated handpumps.

APPLICABILITY

In MODES 1, 2, and 3, the ARVs are required to be OPERABLE.

In MODE 4, the pressure and temperature limitations are such that the probability of an SGTR event requiring ARV operation is low. In addition, the RHR system is available

(continued)

BASES

APPLICABILITY (continued)

to provide the decay heat removal function in MODE 4. Therefore, the ARVs are not required OPERABLE in MODE 4 to satisfy the safety analysis assumptions of the DBA. However, the capability to remove decay heat from an SG required OPERABLE in MODE 4 by LCO 3.4.6, "RCS Loops - MODE 4" is implicit in the requirement for an OPERABLE SG and may require the associated ARV be capable of removing that heat if the normal decay heat removal system (steam dump) is not available.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ARV line inoperable, action must be taken to restore OPERABLE status within 30 days. The 30 day Completion Time is reasonable considering the low probability of an SGTR event coincident with a loss of offsite power requiring the use of the ARVs and the redundant capability afforded by the remaining OPERABLE ARV lines, a nonsafety grade backup in the Steam Dump System, and MSSVs.

B.1

With two or more required ARV lines inoperable, action must be taken to restore all but one required ARV line to OPERABLE status. Since the block valve can be closed to isolate an ARV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ARV 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 ARV lines. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second required ARV is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only intended if the second MSIV in one steam line is found inoperable with one MSIV already inoperable, or if both MSIVs in one steam line are inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 4).

(continued)

BASES

ACTIONS

C.1 and C.2

If the ARV 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 18 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 3.7.4.1

To perform a controlled cooldown of the RCS, the ARVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the ARVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ARV during a unit cooldown may satisfy this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 10.3.

2. FSAR, Subsection 15.6.3.

3. WCAP-11731, LOFTTR2 Analysis for a Steam Generator Tube Rupture Event for the Vogtle Electric Generating Plant Units 1 and 2, January 1988, and Westinghouse letter GP-16886, J. L. Tain to J.B. Beasley, Jr., SGTR Analysis With Revised Operator Action Times and SECL 98-124, Revision 0, dated December 4, 1998.

4. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through separate and independent suction lines from the condensate storage tank (CST) (LCO 3.7.6, “Condensate Storage Tank (CST)”) and pump to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping outside containment. 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, “Main Steam Safety Valves (MSSVs)”) or atmospheric relief valves (LCO 3.7.4, “Atmospheric Relief Valves (ARVs)”). If the main condenser is available, steam may be released via the steam dump valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent Class 1E power supply and feeds two steam generators, although each pump has the capability to be realigned by local manual valve alignment to feed other steam generators. The steam turbine driven AFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feedlines will supply 100% of the requirements of the turbine driven AFW pump. The turbine driven AFW pump supplies a common header capable of feeding all steam generators with DC powered control valves actuated to the appropriate steam generator by the Engineered Safety Feature Actuation System (ESFAS). Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, hot standby, transient, and accident conditions.

(continued)

BASES

BACKGROUND (continued)

The AFW 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 AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ARVs.

The AFW System actuates automatically on steam generator water level — low — low by the ESFAS (LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation"). The system also actuates on loss of offsite power, safety injection, or trip of all MFW pumps.

The AFW System is discussed in the FSAR, Subsection 10.4.9 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW 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 lowest steam generator safety valve set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks. The OPERABILITY of the AFW system in MODE 4 is not assumed in the safety analysis.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of MFW, and

c. Loss of non-emergency AC power to the plant auxiliaries.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of the steam turbine driven AFW pump. In such a case, the ESFAS logic may not detect the affected steam generator if the backflow check valve to the affected MFW header worked properly. One motor driven AFW pump would deliver to the broken MFW header (limited by flow restrictor installed in the AFW line) until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generators by the other AFW line and the redundant AFW pump.

The analyses of the events discussed in UFSAR Sections 15.2.6, “Loss of Nonemergency AC Power to the Plant Auxiliaries,” and 15.2.7, “Loss of Normal Feedwater Flow,” assume that both motor driven AFW pumps provide auxiliary feedwater flow to all four steam generators. The limiting single failure in the analyses of these events is the failure of the turbine-driven AFW pump.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three 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 two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs. The steam supply valves (1/2HV-3019 and 1/2HV-3009) for the turbine driven AFW pump are powered

(continued)

BASES

LCO (continued)

from 125 V MCCs 1/2AD1M and 1/2BD1M, respectively. Suction header valve 1/2HV-5113, pump block valve 1/2HV-5106, and discharge header valves 1/2HV-5120, 5122, 5125, and 5127 are powered from 125 V MCC 1/2CD1M. If 125 V MCC 1/2AD1M or 1/2BD1M becomes inoperable, the affected steam supply valve is to be considered inoperable. If both 1/2AD1M and 1/2BD1M become inoperable, the turbine driven AFW train is to be considered inoperable. If 125 V MCC 1/2CD1M becomes inoperable, the turbine driven AFW train is to be considered inoperable.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to separate steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. The AFW pumphouse ESF supply fans and associated dampers must be OPERABLE to support operation of the motor driven pumps, and the ESF outside air intake and exhaust dampers must be OPERABLE to support operation of the turbine driven pump.

The failure of all four SG sample automatic isolation valves will not prevent the turbine driven AFW system from meeting its safety function. The margins of the turbine driven AFW system are sufficient to meet accident analyses when up to four SG sample automatic isolation valves are not OPERABLE.

The SG sample automatic isolation valves are not required for the AFW system to meet its intended safety function on either unit. The margins of the AFW system are sufficient to meet accident analyses when up to four SG sample automatic isolation valves are not OPERABLE.

(continued)

BASES

LCO (continued)

Note that while SG sample automatic isolation valve failures may not cause the AFW system to become INOPERABLE, such failures must still be evaluated for their impacts to other design functions and effects on accident analyses such as post-accident dose consequence analyses which assume that valves will automatically isolate (see GP-19794 for example).

Although the AFW System can be used in MODE 4 to add to SG inventory when the SG is being used to support RCS operability requirements in accordance with LCO 3.4.6, the LCO does not require the AFW System to be OPERABLE in MODE 4.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost.

In MODE 4 the AFW System may be used for heat removal via the steam generators, but is not required since the RHR System is available in this MODE.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A Note prohibits the application of LCO 3.0.4b to an inoperable AFW train. There is an increased risk associated with an AFW train inoperable and the provisions of LCO 3.0.4b, 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

If the turbine driven AFW train is inoperable due to one inoperable steam supply, or if turbine driven pump is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. For the inoperability of the turbine driven AFW pump due to one inoperable steam supply, the 7 day Completion time is reasonable since there is a redundant steam supply line for the turbine driven pump and the turbine driven train is still capable of performing its specified function for most postulated events. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 3).

(continued)

BASES

ACTIONS

A.1 (continued)

b. For the inoperability of a turbine driven AFW pump while in MODE 3 immediately subsequent to a refueling, the 7 day Completion time is reasonable due to the minimal decay heat levels in this situation. A Risk Informed Completion Time cannot be applied in MODE 3.

c. For both the inoperability of the turbine driven pump due to one inoperable steam supply and an inoperable turbine driven AFW pump while in MODE 3 immediately following a refueling, the 7 day Completion time is reasonable due to the availability of redundant OPERABLE motor driven AFW pumps; and due to the low probability of an event requiring the use of the turbine driven AFW pump. A Risk Informed Completion Time cannot be applied in MODE 3.

Condition A is modified by a Note which limits the applicability of the Condition for an inoperable turbine driven AFW pump in MODE 3 to when the unit has not entered MODE 2 following a refueling. Condition A allows one AFW train to be inoperable for 7 days vice the 72 hour Completion Time in Condition B. This longer Completion Time is based on the reduced decay heat following refueling and prior to the reactor being critical.

B.1

With one of the required AFW trains (pump or flow path) inoperable for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the AFW System, the time needed for repairs, and the low probability of a DBA occurring during this time period. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

C.1 and C.2

With one of the required motor driven AFW trains (pump or flow path) inoperable and the turbine driven AFW train inoperable due to one inoperable steam supply, action must be taken to restore the affected equipment to OPERABLE status within 24 hours. Assuming no single active failures when in this condition, the accident (a FWLB or MSLB) could result in the loss of the

(continued)

ACTIONS

C.1 and C.2 (continued)

remaining steam supply to the turbine driven AFW pump due to the faulted SG. In this condition the AFW system may no longer be able to meet the required flow to the SGs assumed in the safety analysis due to the potential for the remaining AFW pump feeding a faulted SG.

The 24 hour Completion Time is reasonable based on the remaining OPERABLE steam supply to the turbine driven AFW pump, the availability of the remaining OPERABLE motor driven AFW pump, and the low probability of an event occurring that would require the inoperable steam supply to be available for the turbine driven AFW pump.

D.1

If two AFW trains are inoperable for reasons other than Condition C, the Required Action is to restore the inoperable AFW trains to OPERABLE status within 1 hour to regain a method of decay heat removal. Although the Required Action is to restore “trains”, restoration of only one train is required to exit this condition. With one train restored and one train inoperable, Condition D is no longer applicable. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of at least one train. Alternatively, a Risk Informed Completion Time can be determined.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second AFW train is intentionally made inoperable. Required Action D.1 is not intended for voluntary removal of redundant systems or components from service. The Required Action is intended only when the second AFW train is found inoperable with one AFW train already inoperable, or if two AFW trains are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 3).

In MODE 4, AFW is not required since RHR is available.

E.1 and E.2

When the Required Actions of Conditions A, B, C, or D 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

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

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.

In MODE 4, AFW is not required since RHR is available.

F.1

If all three AFW 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 AFW train to OPERABLE status.

Required Action F.1 is modified by a Note indicating that all required MODE changes are suspended until one AFW 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. The correct position is the position of the valves necessary to support the operational needs of the plant at that time, including during low power operation and surveillance testing, provided that the requirements of the Technical Specification safety analysis are met. 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.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1 (continued)

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, (i.e., the intended safety function) continues to be maintained.

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

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME OM Code (Ref. 2). Because it is undesirable to introduce cold AFW 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 as discussed in the ASME OM Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement. The 31 day frequency on a STAGGERED TEST BASIS results in testing each pump once every 3 months, as required by Ref. 2.

In addition to the acceptance criteria of the INSERVICE TESTING PROGRAM, performance of this SR also verifies that pump performance is greater than or equal to the performance assumed in the safety analysis.

This SR is modified by a Note allowing the SR to be deferred until suitable test conditions are established. This deferral may be required because there may be insufficient steam pressure to perform the test.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator 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. However, for the turbine driven AFW train this SR may be performed in conjunction with ASME OM Code full flow check valve testing which must be performed when steam is available to run the turbine driven AFW pump.

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. However, for the turbine driven AFW train this SR must be performed when steam is available to run the pump.

This SR is modified by two Notes. The first Note allows the SR to be deferred until suitable test conditions are established. This deferral may be required because there may be insufficient steam pressure to perform the test. The second Note states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.4 (continued)

is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW system, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.5 and SR 3.7.5.6

These surveillances demonstrate that each AFW pumphouse ESF supply fan 1/2-1593-B7-001 and 1/2-1593-B7-002 and associated shutoff dampers actuate to their correct position on a simulated or actual high room temperature signal, and that the ESF outside air intake and exhaust dampers for the turbine-driven AFW pump actuate to the correct position on a simulated or actual turbine-driven AFW pump automatic start signal. These HVAC systems provide ventilation to limit the air temperature in the AFW pump rooms and are required to support the OPERABILITY of the associated AFW pump. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Subsection 10.4.9.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).

3. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The two CSTs (V4001 and V4002) provide redundant safety grade sources of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CSTs provide a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves.

When the main steam isolation 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. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena. The CST is designed to Seismic Category I to ensure availability of the feedwater supply.

A description of the CST is found in the FSAR, Subsection 9.2.6 (Ref. 1).

APPLICABLE SAFETY ANALYSES

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 FSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 60 minutes at MODE 3, steaming through the MSSVs, followed by a cooldown to residual heat removal (RHR) entry conditions.

The limiting event for the condensate volume is the large feedwater line break coincident with a loss of offsite

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

power. Single failures that also affect this event include the following:

a. Failure of the diesel generator powering the motor driven AFW pump to the unaffected steam generator (requiring additional steam to drive the remaining AFW pump turbine); and

b. Failure of the steam driven AFW pump (requiring a longer time for cooldown using only one motor driven AFW pump).

These are not usually the limiting failures in terms of consequences for these events.

A nonlimiting event considered in CST inventory determinations is a break in either the main feedwater or AFW line near where the two join. This break has the potential for dumping condensate until terminated by operator action, since the Auxiliary Feedwater Actuation System would not detect a difference in pressure between the steam generators for this break location. This loss of condensate inventory is partially compensated for by the retention of steam generator inventory.

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

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat for 60 minutes following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine, or before isolating AFW to a broken line.

The CST level required is equivalent to a usable volume of ≥ 340,000 gallons (66% instrument span) which is based on holding the unit in MODE 3 for 4 hours, followed by a 5 hour cooldown to RHR entry conditions at 50°F/hour with one Reactor Coolant Pump in operation. This basis is

(continued)

THIS PAGE APPLICABLE TO UNIT 1 ONLY

BASES

LCO (continued)

established in Reference 4 and exceeds the volume required by the accident analysis.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level. Either CST V4001 or CST V4002 may be used to satisfy the LCO requirement.

APPLICABILITY

In MODES 1, 2, and 3, the CST is required to be OPERABLE.

Due to the reduced heat removal requirements and short period of time in MODE 4 and the availability of RHR in MODE 4, the LCO does not require a CST to be OPERABLE in this MODE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

(continued)

THIS PAGE APPLICABLE TO UNIT 2 ONLY

BASES

LCO (continued)	established in Reference 4 and exceeds the volume required by the accident analysis. The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level. Either CST V4001 or CST V4002 may be used to satisfy the LCO requirement. For Unit 2 only, two CSTs are required to be OPERABLE with a combined safety-related volume of ≥ 378,000 gallons, and the CST aligned to supply the auxiliary feedwater pumps shall have a safety-related volume ≥ 340,000 gallons. The basis for requiring an additional 38,000 gallons of safety-related usable CST inventory is to support the elimination of the bypass line and associated valve bonnet depressurization line for the 2HV-8701B RHR suction isolation valve. The elimination of the bypass line and valve bonnet depressurization line requires an additional 3 hours for a total of 12 hours prior to placing RHR Train A in service. The additional time ensures that the 2HV-8701B valve bonnet and the space between the 2HV-8701B and 2HV-8701A RHR suction isolation valves have depressurized sufficiently to allow the suction isolation valves to be opened.
APPLICABILITY	In MODES 1, 2, and 3, the CST is required to be OPERABLE. Due to the reduced heat removal requirements and short period of time in MODE 4 and the availability of RHR in MODE 4, the LCO does not require a CST to be OPERABLE in this MODE. In MODE 5 or 6, the CST is not required because the AFW System is not required.

(continued)

THIS PAGE APPLICABLE TO UNIT 1 ONLY

BASES (continued)

ACTIONS

A.1 and A.2

If the required CST volume is not within limit, the Completion Time of 2 hours provides sufficient time for the three AFW pumps to be aligned to the OPERABLE CST. This Completion Time is acceptable based on: 1) Operating experience to perform the required valve operations; 2) The ACTIONS being entered as soon as the CST level decreased below the limit, which would most probably leave sufficient capacity in the inoperable CST to support AFW pump operation for at least the 2 hour Completion Time; and 3) The low probability of an event occurring during this interval that would require the CST to be fully OPERABLE.

B.1 and B.2

If the AFW pumps cannot be aligned to an OPERABLE CST 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

CST V4001 (LI-5101 and LI-5111A)
CST V4002 (LI-5104 and LI-5116A)

This SR verifies that the CST contains the required volume of cooling water. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

THIS PAGE APPLICABLE TO UNIT 2 ONLY

BASES (continued)

ACTIONS

A.1 and A.2

If one or both of the CST volumes are not within limits, the volume(s) must be restored to within limits within 2 hours. This Completion Time is acceptable based on : 1) The ACTIONS being entered as soon as the CST level(s) decreased below limit(s), which would provide reasonable assurance of at least sufficient capacity to support AFW operation for at least the 2 hour Completion Time; and 2) The low probability of an event occurring during this interval that would require the CSTs to be fully OPERABLE.

B.1 and B.2

If the AFW pumps cannot be aligned to an OPERABLE CST 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 unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

CST V4001 (LI-5101 and LI-5111A)
CST V4002 (LI-5104 and LI-5116A)

This SR verifies that the CSTs contain the required volumes of cooling water. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Subsection 9.2.6.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. Branch Technical Position RSB 5-1, Rev. 2, July 1981, "Design Requirements of the Residual Heat Removal System."

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW 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, the CCW System also provides this function for the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Nuclear Service Cooling Water System, and thus to the environment.

The CCW System is arranged as two independent, full capacity cooling loops. Each safety related train includes (three) 50% capacity pumps, surge tank, heat exchanger, piping, valves, and instrumentation. Each safety related train is powered from a separate bus. An open surge tank in the system provides pump trip protective functions to ensure that sufficient net positive suction head is available. The pumps in each train are automatically started on receipt of a safety injection signal. Only two out of the three available pumps are required OPERABLE. The third pump serves as a standby to allow maintenance.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Subsection 9.2.2 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

APPLICABLE SAFETY ANALYSES

The CCW System design satisfies the cold shutdown requirements of Regulatory Guide 1.139 (Ref. 2) and Branch Technical Position 5.1 (Ref. 3). The CCW System is designed to meet the cold shutdown requirements within the specified time (36 hours) using a single CCW train. During accident conditions, the calculated CCW system heat load (Btu/hr) is less than the peak heat load experienced during a single train cooldown to cold shutdown conditions (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Therefore, the CCW system has the heat removal capacity to perform its design function under normal as well as accident conditions. The maximum CCW heat exchanger outlet temperature is designed to be less than 120°F during normal cooldown and accident conditions, based upon a Nuclear Service Cooling Water temperature of 100°F (Ref. 4). Normal CCW operating temperature is 100°F at the outlet of the heat exchanger with 105°F at the inlet (Ref. 1). The Emergency Core Cooling System (ECCS) loss of coolant accident (LOCA) analysis and containment OPERABILITY LOCA analysis each model the maximum and minimum performance of the CCW System, respectively. The operation of the CCW System 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 ECCS pumps.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System also functions to cool the unit from RHR entry conditions (T_{cold} < 350°F), to MODE 5 (T_{cold} < 200°F), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the number of CCW and RHR trains operating. One CCW train is sufficient to remove decay heat during subsequent operations with T_{cold} < 200°F.

The CCW System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The CCW trains are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCW train is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CCW must be OPERABLE. At least one CCW train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

(continued)

BASES

LCO (continued)

A CCW train is considered OPERABLE when:

a. Two pumps and associated surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable but does not necessarily make the CCW System inoperable. Consideration should be given to the size of the load isolated and the impact it will have on the rest of the CCW system before determining OPERABILITY.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW 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 Modes 5 or 6, there are no TS OPERABILITY requirements for the CCW System. However, the functional requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is 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 CCW 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.

If one CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, 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.

(continued)

BASES

ACTIONS (continued)

B.1

With both trains of CCW inoperable, the heat load capacity of the CCW system is seriously degraded such that the system may be incapable of providing an adequate heat sink for normal and accident conditions. Consequently, one hour is provided to restore the CCW trains to OPERABLE status. Alternatively, a Completion Time can be determined under the Risk Informed Completion Time Program. Although the Required Action is to restore “trains”, restoration of only one train is required to exit this condition. With one train restored and one train inoperable, CONDITION B is no longer applicable.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second CCW train is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is intended only when the second CCW train is found inoperable with one CCW train already inoperable, or if two CCW trains are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 6).

C.1 and C.2

If the CCW train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 5). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 5, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 3.7.7.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW 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.

SR 3.7.7.2

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. The CCW 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.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Subsection 9.2.2.

2. Regulatory Guide 1.139, Guidance for Residual Heat Removal, May 1978.

3. Branch Technical Position RSB 5-1, Design Requirements of the Residual Heat Removal System, Rev. 2, July 1981.

4. FSAR, Subsection 5.4.7.

5. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

6. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.7 PLANT SYSTEMS

B 3.7.8 Nuclear Service Cooling Water (NSCW) System

BASES

BACKGROUND

The NSCW 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 NSCW System also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The NSCW System consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of three 50% capacity pumps, various safety and nonsafety related component heat exchangers, 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, and all essential valves are aligned to their post accident positions.

Additional information about the design and operation of the NSCW System, along with a list of the components served, is presented in the FSAR, Subsection 3.5.3 (Ref. 4) and Subsection 9.2.1 (Ref. 1). The principal safety related function of the NSCW System is the removal of decay heat from the reactor via the CCW System.

APPLICABLE SAFETY ANALYSES

The design basis of the NSCW System is for one NSCW System train, in conjunction with the CCW System and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA as discussed in the FSAR, 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 ECCS pumps. The NSCW System is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The NSCW System, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR), as discussed in the FSAR, Subsection 5.4.7, (Ref. 3) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCW and RHR System trains that are operating. One NSCW System train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum NSCW System temperature of 95°F occurring simultaneously with maximum heat loads on the system.

The NSCW System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Two NSCW System 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.

An NSCW System train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Two pumps are OPERABLE; and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

APPLICABILITY

In MODES 1, 2, 3, and 4, the NSCW System is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the NSCW System and required to be OPERABLE in these MODES.

In MODES 5 or 6, there are no TS OPERABILITY requirements for the NSCW System. However, the functional requirements of the NSCW System are determined by the systems it supports.

(continued)

BASES (continued)

ACTIONS

A.1

If one NSCW System train is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE NSCW System train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE NSCW System train could result in loss of NSCW System function. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. 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 NSCW System 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 NSCW System train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. 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.

B.1 and B.2

If the NSCW System train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

C.1

With both trains of NSCW inoperable, the NSCW system may be incapable of providing an adequate heat sink for safety related components during design basis accident and transients. Consequently, one hour is provided to restore the NSCW trains to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. Although the Required Action is to restore “trains”, restoration of only one train is required to exit this condition. With one train restored and one train inoperable, CONDITION B is no longer applicable.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second NSCW train is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is intended only when the second NSCW train is found inoperable with one train already inoperable, or if two NSCW trains are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 5).

(continued)

BASES

ACTIONS

C.1 (continued)

Required Action C.1 is modified by a Note stating that LCO 3.0.3 and all other LCO Required Actions requiring entry into MODE 5 are suspended until the NSCW System is capable of supporting the decay heat removal function of one RHR loop. LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” provides requirements for the decay heat removal function in MODE 5 with the RCS loops filled. With both trains of the NSCW System inoperable, the RHR pumps may be incapable of removing the required decay heat load via the RHR heat exchangers. In this condition, no other practical means for conducting a cooldown to MODE 5 exists. It is therefore preferred that the unit not cooldown to MODE 5 conditions, but rather remain in MODE 4 where RCS cooling capability can be maintained by steaming the steam generators. Because the NSCW System is not required to be OPERABLE in MODE 5, the Note does not suspend entry into MODE 5 until the NSCW System is restored to OPERABLE status. The Note suspends the cooldown to MODE 5 conditions until the NSCW System is restored as necessary to support the decay heat removal function of at least one RHR subsystem.

D.1 and D.2

If the Required Actions of Condition C cannot be completed within the required Completion Times, 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, to MODE 4 within 12 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the NSCW System components or systems may render those components inoperable, but does not necessarily affect the OPERABILITY of the NSCW System.

Consideration should be given to the impact that isolating a load will have on the rest of the NSCW System before determining OPERABILITY.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

Verifying the correct alignment for manual, power operated, and automatic valves in the NSCW System flow path provides assurance that the proper flow paths exist for NSCW System 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 3.7.8.2

This SR verifies proper automatic operation of the NSCW System valves on an actual or simulated SI actuation signal. The NSCW 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.

SR 3.7.8.3

This SR verifies proper automatic operation of the NSCW System pumps on an actual or simulated SI actuation signal. The NSCW 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.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Subsection 9.2.1.

2. FSAR, Section 6.2.

3. FSAR, Subsection 5.4.7.

4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

5. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, "Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A (CAC Nos. ME9555 and ME9556).

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 Nuclear Service Cooling Water (NSCW) System and the Component Cooling Water (CCW) System.

The UHS consists of the NSCW System mechanical draft towers. Two 100% capacity redundant NSCW towers are provided for each unit. One tower is associated with each train of the NSCW System. Each NSCW tower consists of a basin that contains the ultimate heat sink water supply and an upper structure that contains four individual fan spray cells where the heat loads are transferred to the atmosphere. Each spray cell contains one safety-related temperature controlled fan. Instrumentation is provided for monitoring basin level and water temperature. The tower basins each contain a safety-related transfer pump to permit the use of the combined storage capacity of the basins. The combined storage capacity of two tower basins provides greater than a 30 day cooling water supply assuming the worst combination of meteorological conditions and accident heat loads which maximize the tower heat load, basin temperature, and evaporative losses.

Additional information on the design and operation of the system, along with a list of components served, can be found in FSAR, Subsection 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. Its maximum post accident heat load occurs 20 minutes after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and RHR are required to remove the core decay heat.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure (e.g., single failure of a manmade structure). The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the UHS.

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 contains a sufficient volume of water at or below the maximum temperature that would allow the NSCW to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the NSCW.

In order to meet these requirements, two NSCW tower basins are required OPERABLE with the following:

1. Basin water level must be ≥ 80.25 feet as measured from the bottom of the basin (73% of instrument span),

2. Basin water temperature must be ≤ 90°F,

3. Two OPERABLE trains of NSCW tower fans/spray cells, each train with the required number of fans/spray cells as specified in Figure 3.7.9-1, and

4. Two OPERABLE NSCW basin transfer pumps.

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 MODES 5 or 6, there are no TS OPERABILITY requirements for the UHS. However, the functional requirements of the UHS are determined by the systems it supports.

(continued)

BASES (continued)

ACTIONS

A.1

If one or more NSCW basins have a water temperature and/or water level not within the limits, action must be taken to restore the water temperature and level to within the limits within 72 hours.

The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hours, the considerable cooling capacity still available in the basin(s), and the time required to reasonably complete the Required Action.

B.1

If one NSCW cooling tower has one required fan/spray cell inoperable when operating in the four fan/spray cell required region of Figure 3.7.9-1, action must be taken to restore the inoperable fan/spray cell to OPERABLE status within 7 days.

The 7-day Completion Time provides an acceptable time for evaluating and repairing problems with a fan/spray cell without allowing the plant to remain in an unacceptable condition for an extended period of time, and is reasonable due to the availability of the redundant OPERABLE NSCW cooling tower, and due to the low probability of an event requiring all four NSCW cooling tower fans/spray cells. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 5).

C.1

If one NSCW cooling tower has one or more required fan(s)/spray cell(s) inoperable for reasons other than Condition B, action must be taken to restore the inoperable fan(s)/spray cell(s) to OPERABLE status within 72 hours.

The 72 hour Completion Time is reasonable based on the low probability of an accident occurring during the 72 hours, the number of available fans/spray cells, and the time required to reasonably complete the Required Action. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 5).

D.1 and D.2

If one NSCW basin transfer pump is inoperable, action must be taken to implement an alternate method of transferring the water

(continued)

ACTIONS

D.1 and D.2 (continued)

to the affected cooling tower basin within 8 days and restore the transfer pump to OPERABLE status within 46 days.

The Completion Times are reasonable based on the low probability of an accident occurring during the time allowed to implement an alternate method, the availability of alternate methods, and the time available before the basin transfer function is required under the worst case accident assumptions.

E.1 and E.2

If two NSCW basin transfer pumps are inoperable, an alternate method of transferring water to at least one cooling tower basin must be implemented within 24 hours and at least one NSCW basin transfer pump restored to OPERABLE status within 8 days.

The safety function of the UHS can be maintained for a minimum of 24 hours with both NSCW basin transfer pumps inoperable and no alternate method of transferring water from one cooling tower basin to the other. An alternate method of transferring water to the applicable basin must be implemented within 24 hours to ensure the UHS can provide adequate cooling for at least 30 days.

The Completion Time of E.1 is provided to allow time to implement an alternate method and is considered acceptable based on the remaining NSCW cooling tower basin capacity, the fact that procedures will be initiated to establish an alternate method of basin transfer, and the low probability of an event occurring during this brief period.

The Completion Time of E.2 is reasonable based on the availability of alternate methods, the time available before the basin transfer function is required under the worst case accident assumptions, and the low probability of an accident occurring during the time allowed to restore one NSCW basin transfer pump to OPERABLE status.

(continued)

BASES (continued)

ACTIONS

F.1 and F.2

If the Required Actions of Conditions A, B, C, D, or E are not completed within their associated Completion Times or if the UHS is inoperable for reasons other than described in Conditions A, B, C, D, or E, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 in 6 hours and in MODE 4 within 12 hours.

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action F.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR verifies that adequate long term (30 day) cooling can be maintained. The specified level also ensures that sufficient NPSH is available to operate the NSCW System pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.2

This SR verifies that the NSCW System is available to cool the CCW 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. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.3

Operating each required NSCW cooling tower fan for ≥ 15 minutes ensures that all required 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.

SR 3.7.9.4

The verification of NSCW basin transfer pump operation includes testing to verify the pump's developed head at the flow test point is greater than or equal to the required developed head. Flow and differential head are normal tests of centrifugal pump performance required by the ASME OM Code (Ref. 3). This test confirms one point on the pumps design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The performance of this surveillance in accordance with the Inservice Testing Program satisfies the requirements of Ref. 3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.5

With one tower fan/spray cell out-of-service this SR verifies that ambient wet-bulb temperature remains within the three fan/spray cell region specified in Figure 3.7.9-1 so that the NSCW system remains capable of performing its design basis function. Requiring this SR when forecasted temperature is > 48°F provides assurance that the ambient wet-bulb temperature specified in Figure 3.7.9-1 will not be exceeded while the fan is out-of-service. The 24-hour frequency is sufficient since the daily peak temperature is expected to occur once in a 24-hour interval. Measurement of the ambient wet-bulb temperature should be made, near the time when the daily peak temperature is expected to occur, with a psychrometer in an open area away from sources of moisture, heat or wind, and within the owner-controlled area at Plant Vogtle.

REFERENCES

1. FSAR, Subsection 9.2.5.
2. Regulatory Guide 1.27.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code).
4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.
5. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Filtration System (CREFS) - Both Units Operating

BASES

BACKGROUND

The CREFS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREFS has a total of four redundant, completely independent, full capacity air filtration trains that recirculate and filter the air in the common Unit 1 and 2 control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CREFS train consists of carbon filter moisture eliminators, high efficiency particulate air (HEPA) filters, electric heaters, cooling coil, and supply and return fans. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system. The filter trains for Unit 1 are powered from the Unit 1 safety feature buses A and B and the filter trains for Unit 2 are powered from the Unit 2 safety feature buses A and B.

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 may encompass 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.

The CREFS is actuated manually or upon receipt of a Control Room Isolation (CRI) signal. The CRI signal results from a safety injection signal or high radiation in the outside air intake. The CRI actuation instrumentation is addressed in LCO 3.3.7, "CREFS Actuation Instrumentation." A CRI signal also isolates the normal HVAC system. Normal open isolation dampers are arranged in series, so that the failure of one damper to close will not prevent

(continued)

BASES

BACKGROUND (continued)

isolation. The CREFS in each unit is equipped with a lead/lag logic control circuit designed to control the operation of the CREFS in such a manner so as to preclude extended automatic start. In each unit, train B is the lead train and will start immediately upon receipt of a CRI signal. If train B fails to start, train A will start.

During the emergency mode of operation, air within the CRE is recirculated continuously through the emergency air conditioning units which contain upstream HEPA filters, charcoal absorbers, downstream HEPA filters, cooling coil, and fan. Cooling water is supplied by the Essential Chilled Water System. The outside air required for pressurization is mixed with the return air before it enters the filtration unit. Each unit has one outside air intake duct located such that it is protected from high energy line breaks, the introduction of airborne radioactive material from release points, and diesel generator exhaust fumes.

The CREFS is designed to maintain a habitable environment in the CRE environment for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or equivalent to any part of the body. This is accomplished by the following CREFS functions:

1. Pressurizing the CRE to 0.125-inch water gage pressure relative to external areas adjacent to the CRE boundary to minimize any unfiltered inleakage into the CRE through the CRE boundary during a radiological accident, and

2. Removal of airborne radioactivity by circulating air through carbon adsorbers.

In addition, the CREFS is designed to ensure that the CRE temperature will not exceed equipment operational requirements following a CRI actuation. This is accomplished by the cooling coils supplied by the Essential Chilled Water System, LCO 3.7.14, "Engineered Safety Features (ESF) Room Cooler and Safety-Related Chiller System" that are part of each CREFS train. At the normal system air flow rate of 19,000 cfm, each CREFS train is capable of maintaining the CRE temperature ≤ 85°F. The CREFS operation in maintaining the CRE temperature and habitability is discussed in the FSAR, Section 6.4 (Ref. 1).

The CREFS contains heaters that are controlled by the relative humidity of the air flowing through the system. The heaters automatically turn on at 70% relative humidity to limit the moisture

(continued)

BASES

BACKGROUND (continued)	content of the carbon adsorbers. Periodic operation of each CREFs train with the heater control circuit energized ensures the moisture content of the adsorbers is maintained ≤ 70% relative humidity. The CREFS is also designed to remain functional during the safe shutdown earthquake, design basis tornado, loss of coolant accident, main steam line or feedwater line break, and single failure of any component in the system.
APPLICABLE SAFETY ANALYSES	The CREFS 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 CREFS 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 FSAR, Chapter 15 (Ref. 2). The CREFS provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the 8 hour toxicity limit is not exceeded in the CRE and there is sufficient time between detection and reaching the short term toxicity limit, such that the operators have time to put on breathing apparatus following a toxic chemical release, as presented in Reference 1. CREFS is not required for toxic gas. The evaluation of a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 1). The worst case single active failure of a component of the CREFS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. The CREFS satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
LCO	Two independent and redundant CREFS trains per unit 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 all ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of a large radioactive release.

(continued)

BASES

LCO (continued)

Each CREFS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure and ensure a CRE temperature of ≤ 85°F are OPERABLE. A CREFS train is OPERABLE when the associated:

a. Fan is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions;

c. Heater, demister, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained; and

d. Cooling coils and associated temperature control equipment are capable of performing their function.

In order for the CREFS 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 isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREFS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

(continued)

BASES (continued)

ACTIONS

The following ACTIONS have been developed to take credit for the redundancy and inherent flexibility designed into the four 100% capacity CREFS trains. These ACTIONS were reviewed to ensure that the system function would be maintained under accident conditions coupled with a postulated single failure. The results of this review are documented in Reference 3.

A.1

With a single CREFS train inoperable for reasons other than Condition D, action must be taken to restore the CREFS train to OPERABLE status, or one train of CREFS in the unaffected unit must be placed in the emergency mode of operation within 7 days. In this condition, the remaining OPERABLE CREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in a loss of the CREFS function for the affected unit. Placing one CREFS train in the unaffected unit in the emergency mode of operation ensures the CRE protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

B.1

With one CREFS train inoperable in each unit for reasons other than Condition D, action must be taken to restore the CREFS trains to OPERABLE status or the two remaining OPERABLE CREFS trains must be placed in the emergency mode of operation within 7 days. In this condition, the remaining OPERABLE CREFS trains are adequate to perform the CRE occupant protection function for each unit. However, the overall reliability is reduced because a failure in one of the OPERABLE CREFS trains could result in a loss of the CREFS function for the affected unit. Placing one CREFS train in the emergency mode of operation in each unit ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE,

(continued)

BASES

ACTIONS

B.1 (continued)

limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS trains to provide protection for the CRE occupants.

C.1

With two CREFS trains inoperable in one unit for reasons other than Condition D, action must be taken to protect the CRE occupants for the affected unit immediately. In this condition, there is no CREFS function for one unit. The two CREFS trains in the unaffected unit must be placed in the emergency mode of operation immediately. Placing two CREFS trains in the emergency mode of operation in the unaffected unit ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. Due to the loss of the CREFS function for one unit, the completion time of immediately is specified.

D.1

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 whole body or its equivalent to any part of the body), 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

(continued)

BASES

ACTIONS

D.1 (continued)

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.

E.1

With the CRE air temperature outside its limit, action must be taken to restore the air temperature to within the limit within 7 days. If the CRE air temperature exceeds its limit, the ability of a single train of CREFS to maintain CRE temperature after a CRI may be affected. The completion time of 7 days is reasonable considering the number of CREFS trains available to perform the required temperature control function and the low probability of an event occurring that would require the CREFS operation during that time.

F.1, F.2, and F.3

If the Required Actions and associated Completion Times of Conditions A, B, or D are not met, action must be taken to place the unit in a condition in which overall plant risk is reduced. Locking closed the outside air (OSA) dampers in the affected unit and locking open the OSA dampers in the unaffected unit within 1 hour, ensure that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE CREFS trains. The affected unit(s) must also be placed in MODE 3 within 7 hours and MODE 4 within 13 hours. These actions ensure that if the

(continued)

BASES

ACTIONS

F.1, F.2, and F.3 (continued)

CRE occupants cannot be protected from all postulated accident and single failure conditions, the unit or units are placed in a MODE in which overall plant risk is reduced. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 8). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 8, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective. The allowed Completion Times are reasonable, based on operating experience, to perform the Required Actions and to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

Required Action F.1 is modified by a Note that excepts Conditions B and D. Conditions B and D affect both units, and Required Action F.1 is based on a single affected unit. Therefore, upon entry into Condition F from Condition B or D, only Required Actions F.2 and F.3 apply.

Required Action F.3 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

G.1, G.2, and G.3

If the Required Actions and associated Completion Times of Conditions C or E are not met, action must be taken to place the unit in a condition where the inoperable CREFS train(s) are no

(continued)

BASES

ACTIONS

G.1, G.2, and G.3 (continued)

longer required. Locking closed the outside air (OSA) dampers in the affected unit and locking open the OSA dampers in the unaffected unit within 1 hour, ensures that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE CREFS trains. The affected unit(s) must also be placed in MODE 3 within 7 hours and MODE 5 within 37 hours, which removes the requirement for CRE occupant protection in the event of an SI in the affected unit(s). These actions ensure that if the CRE occupants cannot be protected from all postulated accident and single failure conditions, the unit or units are placed in a MODE where the protection is no longer required. The allowed Completion Times are reasonable, based on operating experience, to perform the Required Actions and to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

Required Action G.1 is modified by a Note that excepts Condition E. Condition E affects both units, and Required Action G.1 is based on a single affected unit. Therefore, upon entry into Condition G from Condition E, only Required Actions G.2 and G.3 apply.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

The CREFS is required to maintain the CRE temperature ≤ 85°F in the event of a CRI. The maintenance of the CRE below this temperature ensures the operational requirements of equipment located in the CRE will not be exceeded. To accomplish this function, the CREFS air flow is directed through cooling coils which are supplied by the Essential Chilled Water System. The design cooling capacity of the CREFS and the limitation of the normal CRE ambient temperature (before CRI) ensure the capability of the CREFS to maintain the CRE temperature within limit after a CRI. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.2

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train in accordance with the Surveillance Frequency Control Program provides an adequate check of this system.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.2 (continued)

Operations with the heater control circuit energized allows the heaters to operate as necessary to reduce the humidity in the ambient air and ensure excessive moisture (> 70% relative humidity) is removed from the adsorber and HEPA filters. Flow (FI-12191, FI-12192) through the HEPA filters and charcoal adsorbers is verified. Operation with the heater control circuit energized 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 Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.3

This SR verifies that the required CREFS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREFS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.4

This SR verifies that each CREFS train starts and operates on an actual or simulated actuation signal. The SR excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.5

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 whole body or its equivalent to any part of the body 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 D must be entered. Required Action D.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. 5) 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 D.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 7). 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.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Section 6.4.

2. FSAR, Chapter 15.

3. VEGP Calculation No. X6CNA.09.01, Control Room HVAC Technical Specifications, October 21, 1988.

4. Regulatory Guide 1.52, Rev. 2.

5. Regulatory Guide 1.196.

6. NEI 99-03, "Control Room Habitability Assessment," June 2001.

7. 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).

8. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Emergency Filtration System (CREFS — One Unit Operating)

BASES

BACKGROUND

A description of the CREFS is provided in the Bases for LCO 3.7.10, "CREFS — Both Units Operating."

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of the Bases for LCO 3.7.10 also applies to this Bases section.

The CREFS provides airborne radiological protection for the control room envelope (CRE) occupants in the event of the most limiting design basis accident (DBA) in the operating unit as well as for a design basis fuel handling accident in the shutdown unit. The CREFS also provides protection from smoke and hazardous chemicals to the CRE occupants.

LCO

As this LCO requires all four CREFS trains OPERABLE, the LCO section of the Bases for LCO 3.7.10 also applies to this Bases section.

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 isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4 the CREFS must be OPERABLE to ensure that the CRE will remain habitable and maintain the CRE temperature during and following a DBA in the operating unit.

The LCO requirements and ACTIONS of this LCO bound the movement of irradiated fuel or CORE ALTERATIONS in the shutdown unit as well. During movement of irradiated fuel or CORE ALTERATIONS, the CREFS must be OPERABLE to

(continued)

BASES

APPLICABILITY (continued)

ensure that the CRE will remain habitable and maintain the CRE temperature during and following a DBA.

ACTIONS

The following ACTIONS have been developed to take credit for the redundancy and inherent flexibility designed into the four 100% capacity CREFS trains.

These ACTIONS were reviewed to ensure that the system function would be maintained under accident conditions coupled with a postulated single failure. The results of this review are documented in Reference 1.

A.1

With a single CREFS train inoperable in the operating unit for reasons other than Condition F, action must be taken to restore the CREFS train to OPERABLE status or one CREFS train in the shutdown unit must be placed in the emergency mode of operation within 7 days. In this condition the remaining OPERABLE CREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in a loss of the CREFS function for the operating unit. Placing one CREFS train in the shutdown unit in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

B.1 and B.2

With a single CREFS train inoperable in the shutdown unit for reasons other than Condition F, action must be taken to restore the CREFS train to OPERABLE status or lock closed the outside air (OSA) dampers in the shutdown unit and lock open the OSA dampers in the operating unit or one train of CREFS in the operating unit must be placed in the emergency mode of operation within 7 days.

In this condition the remaining OPERABLE CREFS train is adequate to perform the CRE occupant protection function.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in a loss of the CREFS function for the shutdown unit. Locking closed the OSA dampers in the shutdown unit and locking open the OSA dampers in the operating unit ensure that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE CREFS trains. Placing one CREFS train in the operating unit in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

C.1 and C.2

With one CREFS train inoperable in each unit for reasons other than Condition F, action must be taken to restore the CREFS trains to OPERABLE status or lock close the OSA dampers in the shutdown unit and lock open the OSA dampers in the operating unit and place the OPERABLE CREFS train in the shutdown unit in the emergency mode within 7 days. Locking closed the OSA dampers in the shutdown unit and locking open the OSA dampers in the operating unit ensure that all CRE air intake is monitored by redundant radiogas monitors that actuate an OPERABLE CREFS train. Placing the OPERABLE CREFS train of the shutdown unit in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident and single failure conditions.

In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

(continued)

BASES

ACTIONS (continued)

D.1

With two CREFS trains inoperable in the operating unit for reasons other than Condition F, action must be taken to place other CREFS trains in the shutdown unit in the emergency mode immediately. In this condition, there is no CREFS function for the operating unit. The two CREFS trains in the shutdown unit must be placed in the emergency mode of operation immediately. Placing two CREFS trains in the emergency mode of operation in the shutdown unit ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. Due to the loss of the CREFS function for one unit, the completion time of immediately is specified.

E.1 and E.2

With two trains inoperable in the shutdown unit for reasons other than Condition F, action must be taken to lock close the OSA dampers in the shutdown unit and lock open the OSA dampers in the operating unit or place both the operating unit CREFS trains in the emergency mode immediately. In this condition, there is no CREFS function for the shutdown unit. Locking closed the OSA dampers in the shutdown unit and locking open the OSA dampers in the operating unit ensure that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE CREFS trains. Placing two CREFS trains in the emergency mode of operation in the operating unit ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. Due to the loss of the CREFS function for one unit, the completion time of immediately is specified.

F.1

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 whole body or its equivalent to any part of the body), 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.

(continued)

BASES

ACTIONS

F.1 (continued)

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.

G.1

With the CRE air temperature outside its limit, action must be taken to restore the air temperature to within the limit within 7 days. If the CRE air temperature exceeds its limit, the ability of a single train of CREFS to maintain CRE temperature after a CRI may be affected. The completion time of 7 days is reasonable considering the number of CREFS trains available to perform the required temperature control function and the low probability of an event occurring that would require the CREFS operation during that time.

H.1 and H.2

If the Required Actions and associated Completion Times of Conditions A, B, C or F are not met for the operating unit, action must be taken to place the unit in a condition in which overall plant risk is reduced. The operating unit must be placed in MODE 3 within 6 hours and MODE 4 within 12 hours. These actions ensure that if the CRE occupants cannot be protected from all postulated accident and single failure conditions, the unit is placed in a MODE where overall plant risk is reduced.

(continued)

BASES

ACTIONS

H.1 and H.2 (continued)

Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 2). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 2, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action H.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

The allowed Completion Times are reasonable, based on operating experience to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

I.1 and I.2

If the Required Actions and associated Completion Times of Condition D, E, or G are not met for the operating unit, action must be taken to place the unit in a condition where the inoperable CREFS train(s) are no longer required. The operating unit must be placed in MODE 3 within 6 hours and MODE 5 within 36 hours, which removes the requirement for CRE occupant protection in the event of an SI in the operating unit. These actions ensure that if the CRE occupants cannot be protected from all postulated accident and single failure conditions, the unit is placed in a MODE where the protection is no longer required. The allowed Completion Times are reasonable, based on operating experience to reach the required unit conditions from full power conditions in an orderly manner without challenging unit systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

SR 3.7.11.1 requires that the SRs specified in LCO 3.7.10 be applicable for this LCO as well. The description and Frequencies of those required SRs are included in the Bases for LCO 3.7.10.

REFERENCES

1. VEGP Calculation No. X6CNA.09.01, Control Room HVAC Technical Specifications, October 21, 1988.
2. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.12 Control Room Emergency Filtration System (CREFS) — Both Units Shut Down

BASES

BACKGROUND

A description of the CREFS is provided in the Bases for LCO 3.7.10, "CREFS — Both Units Operating."

APPLICABLE SAFETY ANALYSES

The Applicable portions of the Safety Analyses section of the Bases for LCO 3.7.10 also apply to this Bases section.

During movement of irradiated fuel or CORE ALTERATIONS, the CREFS ensures that the control room envelope (CRE) will remain habitable for the CRE occupants in the event of the most limiting design basis fuel handling accident in either shutdown unit. The CREFS provides protection from smoke and hazardous chemicals to the CRE occupants. The CREFS also functions to maintain the CRE temperature after a Control Room Isolation (CRI).

LCO

As this LCO requires all four CREFS trains OPERABLE, the LCO section of the Bases for LCO 3.7.10 also applies to this Bases section.

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 isolation is indicated.

APPLICABILITY

The Applicability specifies when both units have an average RCS temperature of ≤ 200°F during movement of irradiated fuel or CORE ALTERATIONS. The temperature related Applicability requires CREFS OPERABLE even in a defueled state where no MODE is applicable and fuel may still be moved or in movement.

(continued)

BASES

APPLICABITLITY (continued)

During the movement of irradiated fuel or CORE ALTERATIONS in either unit, the CREFS must be OPERABLE to provide a habitable environment for the CRE occupants and maintain the CRE temperature during and following a design basis radiological release.

ACTIONS

The following ACTIONS have been developed to take credit for the redundancy and inherent flexibility designed into the four 100% capacity CREFS trains. These ACTIONS were reviewed to ensure that the system function would be maintained for the design basis accident. The results of this review are documented in Reference 1.

A.1 and A.2

With a single CREFS train inoperable in one of the shutdown units, action must be taken to restore the CREFS train to OPERABLE status or lock closed the outside air (OSA) dampers in the affected unit and lock open the OSA dampers in the unaffected unit or one CREFS train in the unaffected unit must be placed in the emergency mode of operation within 7 days. In this condition, the remaining OPERABLE CREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in a loss of the CREFS function for the affected unit. Locking closed the OSA dampers in the affected unit and locking open the OSA dampers in the unaffected unit ensure that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE CREFS trains. Placing one CREFS train in the unaffected unit in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident and single failure conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

B.1

With a CREFS train inoperable in each shutdown unit, action must be taken to restore the CREFS train to OPERABLE status or place one train of CREFS in the emergency mode of operation within 7 days. In this condition, the remaining OPERABLE

(continued)

BASES

ACTIONS

B.1 (continued)

CREFS trains are adequate to perform the CRE occupant protection function.

However, the overall reliability is reduced. Placing one CREFS train in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS trains to provide protection for the CRE occupants.

C.1 and C.2

With two CREFS trains inoperable in one unit, action must be taken to lock closed the OSA dampers in the affected unit and lock open the OSA dampers in the unaffected unit or place one train of CREFS in the unaffected unit in the emergency mode of operation immediately. In this condition, the affected unit has no CREFS function. Locking closed the OSA dampers in the affected unit and locking open the OSA dampers in the unaffected unit ensures that all CRE air intake is monitored by redundant radiogas monitors that actuate OPERABLE redundant CREFS trains. Placing a CREFS train in the unaffected unit in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. Since in this condition one unit has no CREFS function, an immediate Completion Time is specified.

D.1, D.2.1, D.2.2.1, and D.2.2.2

With three CREFS trains inoperable, action must be taken to place the remaining CREFS train in the emergency mode of operation or lock closed the OSA dampers in the unit with two inoperable systems and lock open the OSA dampers in the unit with one inoperable system immediately.

If the OSA dampers are positioned according to Required Action D.2.1, one train of CREFS must then be restored to

(continued)

BASES

ACTIONS

D.1, D.2.1, D.2.2.1, and D.2.2.2 (continued)

OPERABLE status or the remaining CREFS train must be placed in the emergency mode of operation within the following 7 days. Placing the remaining CREFS train in the emergency mode of operation ensures the CRE occupants remain protected for all postulated accident conditions. In addition, the capability of the CREFS to pressurize the CRE, limit the radiation dose, and provide adequate cooling remains undiminished. Alternatively, locking closed the OSA dampers in the unit with two inoperable CREFS trains and locking open the OSA dampers in the unit with one OPERABLE CREFS train ensures that all CRE air intake is monitored by redundant radiogas monitors that actuate an OPERABLE CREFS train. Once the dampers have been positioned, 7 days are allowed before the remaining CREFS train must be placed in the emergency mode of operation. The 7 day Completion Time is based on the low probability of an event occurring during this time interval that would require CREFS operation and the capability of the remaining OPERABLE CREFS train to provide protection for the CRE occupants.

E.1 and E.2

With four trains of CREFS inoperable, or if the CREFS train required to be in the emergency mode of operation by the other Required Actions of this LCO is not capable of being powered by an OPERABLE emergency power source, or with one or more CREFS trains inoperable due to an inoperable CRE boundary, action must be taken to suspend movement of irradiated fuel assemblies and CORE ALTERATIONS immediately. In this condition, the CRE occupants cannot be fully protected from accidents resulting in significant releases of radioactivity. Suspending the movement of irradiated fuel and CORE ALTERATIONS removes the potential for accidents that may release significant amounts of airborne radioactivity.

F.1

With the CRE air temperature outside its limit, action must be taken to restore the air temperature to within the limit within 7 days. If the CRE air temperature exceeds its limit, the ability of a single train of CREFS to maintain CRE temperature after a CRI may be affected. The completion time of 7 days is reasonable considering the number of CREFS trains available to perform the required temperature control function and the low probability of an event occurring that would require the CREFS operation during that time.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.7.12.1</u> SR 3.7.12.1 requires that the SRs specified in LCO 3.7.10 be applicable for this LCO as well. The description and Frequencies of those required SRs are included in the Bases for LCO 3.7.10.
REFERENCES	1. VEGP Calculation No. X6CNA.09.01, Control Room HVAC Technical Specifications, October 21, 1988.

B 3.7 PLANT SYSTEMS

B 3.7.13 Piping Penetration Area Filtration and Exhaust System (PPAFES)

BASES

BACKGROUND

The PPAFES maintains a negative pressure in the piping penetration area and Engineered Safety Feature (ESF) pump rooms and filters the exhaust from the negative pressure boundary. The PPAFES minimizes the release of airborne radioactivity to the outside atmosphere resulting from recirculation line and component leakage into the piping penetration area Emergency Core Cooling System (ECCS) and ESF pump rooms during an accident condition.

The PPAFES consists of two independent and redundant trains. Each train consists of a heater, a prefilter or demister, 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, as well as demisters, functioning to reduce the relative humidity of the air stream, also form part of the system. A second bank of HEPA filters, which follows the adsorber section, collects carbon fines and provides backup in case of failure of the main HEPA filter bank. The downstream HEPA filter is not credited in the accident analysis. The system initiates filtered ventilation following receipt of a containment ventilation isolation signal.

The PPAFES is a standby system, parts of which may also operate during normal unit operations. During emergency operations, the PPAFES dampers are realigned and fans are started to initiate filtration. Upon receipt of the actuating signal(s), normal air discharges from the penetration room, the penetration room is isolated, and the stream of ventilation air discharges through the system filter trains. The prefilters remove any large particles in the air, as well as any entrained water droplets, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The PPAFES is discussed in the FSAR, Subsections 6.5.1, 9.4.3, and 15.6.5 (Refs. 1, 2, and 3, respectively) since it may be used for normal, as well as post accident, atmospheric cleanup functions. Heaters are included for

(continued)

BASES

BACKGROUND (continued)

moisture removal. The primary purpose of the heaters is to maintain the relative humidity at an acceptable level; however, the VEGP dose analysis assumes no heater operation and an iodine removal efficiency consistent with the iodine removal efficiency in Regulatory Guide 1.52 (Ref. 4) for systems designed to operate inside primary containment (i.e., no humidity control). Therefore, the heaters are not required for PPAFES OPERABILITY.

APPLICABLE SAFETY ANALYSES

The PPAFES design basis is established by the large break loss of coolant accident (LOCA). The system evaluation assumes 2 gpm continuous leakage and a 50 gpm leak for 30 minutes due to a passive failure during a Design Basis Accident (DBA). The system restricts the radioactive release to within the 10 CFR 100 (Ref. 4) limits, or the NRC staff approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits). The analysis of the effects and consequences of a large break LOCA are presented in Reference 3.

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

LCO

Two independent and redundant trains of the PPAFES are required to be OPERABLE to ensure that at least one train is available, assuming there is a single failure disabling the other train coincident with a loss of offsite power.

The PPAFES is considered OPERABLE when the individual components necessary to control radioactive releases are OPERABLE in both trains. A PPAFES 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 functions; and

c. Demister, ductwork, valves, and dampers are OPERABLE and air circulation can be maintained.

The LCO is modified by a Note allowing the PPAFES boundary to be opened intermittently under administrative controls without requiring entry into the Condition for an inoperable pressure boundary. For

(continued)

BASES

LCO (continued)

entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for PPAFES isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the PPAFES is required to be OPERABLE, consistent with the OPERABILITY requirements of the ECCS.

In MODE 5 or 6, the PPAFES is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

With one PPAFES train inoperable, the action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the PPAFES function. The 7 day Completion Time is appropriate because the risk contribution of the PPAFES is less than that of 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 period, and the remaining train providing the required capability.

B.1

If the PPAFES boundary is inoperable, the PPAFES trains cannot perform their intended function. Actions must be taken to restore an OPERABLE PPAFES boundary within 24 hours. During the period that the PPAFES boundary is inoperable, appropriate compensatory measures (consistent with the intent, as applicable, of GDC 19, 60, 64 and 10 CFR 100) will be utilized to ensure the necessary physical security and to minimize the release of radioactive material to the atmosphere outside the building. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24-hour Completion Time is reasonable based on the low

(continued)

BASES

ACTIONS

B.1 (continued)

probability of a DBA occurring during this time period and the use of compensatory measures. The 24-hour Completion Time is a typically reasonable time to test, diagnose, and plan and possibly execute a repair of most problems with the PPAFES boundary.

C.1 and C.2

If the inoperable train cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which overall plant risk is reduced. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 5). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 5, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action C.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system. Flow (FI-12629 and FI-12542) through the HEPA and charcoal filters is verified. Systems that do not take credit for humidity control (heaters) need only be operated for ≥ 15 minutes to demonstrate the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.13.2

This SR verifies that the required PPAFES testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The PPAFES filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, 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.

SR 3.7.13.3

This SR verifies that each PPAFES starts and operates on an actual or simulated containment ventilation isolation signal. The SR excludes automatic dampers and valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers or valves that are locked, sealed, or otherwise secured in the actuated position since the affected dampers or valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve or damper in a locked, sealed, or otherwise secured position requires an assessment of the operability of the system or any supported systems, including whether it is necessary for the valve or damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve or damper to the non-actuated position requires verification that the SR has been met within its required Frequency. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.4

This SR verifies the integrity of the penetration room enclosure. The ability of the penetration room to maintain a negative pressure, with respect to potentially uncontaminated adjacent areas, is periodically tested to verify proper function of PPAFES. During the post accident mode of operation, the PPAFES is designed to maintain a negative pressure ≥ 0.250 inches water gauge relative to atmospheric pressure (PDI-2550 and PDI-2551 in rooms R1-63 and R1-64) at a flow rate of 15,500 ± 10% cfm in the penetration room to prevent unfiltered LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The minimum system flow rate maintains a slight negative pressure in the penetration room area, and provides sufficient air velocity to transport particulate contaminants, assuming only one filter train is operating. The number of filter elements is selected to limit the flow rate through any individual element to about 15,500 ± 10% cfm. The maximum limit ensures that the flow through, and pressure drop across, each filter element are not excessive.

The number and depth of the adsorber elements ensure that, at the maximum flow rate, the residence time of the air stream in the charcoal bed achieves the desired adsorption rate. At least a 0.250 second residence time per 2 inch of bed depth is necessary for an assumed 90% efficiency.

The filters have a certain pressure drop at the design flow rate when clean. The magnitude of the pressure drop indicates acceptable performance, and is based on manufacturers' recommendations for the filter and adsorber elements at the design flow rate. An increase in pressure drop or a decrease in flow indicates that the filter is being loaded or that there are other problems with the system.

This test is conducted along with the tests for filter penetration; thus, the 18 month Frequency is consistent with that specified in Reference 5. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

BASES (continued)

REFERENCES

1. FSAR, Subsection 6.5.1.
2. FSAR, Subsection 9.4.3.
3. FSAR, Subsection 15.6.5.
4. 10 CFR 100.
5. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

B 3.7 PLANT SYSTEMS

B 3.7.14 Engineered Safety Feature (ESF) Room Cooler and Safety-Related Chiller System

BASES

BACKGROUND

The ESF room cooler and safety-related chiller system provides cooling to ESF equipment rooms during abnormal, accident, and post accident conditions. The ESF room coolers supplement the normal HVAC system in cooling certain rooms during normal operations. The essential chilled water system supplies chilled water to the cooling coils for all ESF room coolers and the Control Room Emergency Filtration System (CREFS).

The ESF room coolers are designed to maintain the ambient air temperature within the continuous duty rating of the ESF equipment served by the system. Each equipment room is cooled by a fan cooler and associated chiller that are powered from the same ESF train as that associated with the equipment in the room. Thus, a power failure or other single failure to one cooling system train will not prevent the cooling of redundant ESF equipment in the other train.

In addition to a manual start capability, automatic cooling of each ESF equipment room is initiated by three possible signals. All room coolers start upon receipt of a high temperature signal from the associated room. Certain room coolers will start upon receipt of an equipment running signal or a safety injection (SI) signal. The equipment running signal is used to provide supplemental cooling for the normal ventilation system in some ESF equipment rooms. The high room temperature signal supplements the normal cooling system function and does not constitute a credited safety function. The SI signal or the equipment running signal is the credited safety function automatic start and will start only those ESF room coolers which are required to operate during an SI. In addition the safety-related chillers receive an automatic start from the Control Room Isolation (CRI) signal to provide chilled water to the CREFS. In addition, the containment spray pump room coolers start when the containment spray pumps start. Containment spray is actuated when containment pressure reaches the Hi-3 setpoint, which may occur following a loss of coolant accident or a steam line break.

The ESF room cooler and safety-related chiller system is seismic category 1 and remains operational during and after a safe shutdown earthquake. This system and associated

(continued)

BASES

BACKGROUND (continued)	instrumentation is described in greater detail in FSAR Sections 7.3 and 9.4, References 1 and 2, respectively.

APPLICABLE SAFETY ANALYSES

The design basis of the ESF room cooler and safety-related chiller system is to maintain air temperatures as required in rooms containing safety-related equipment during and after a design basis loss of coolant accident (LOCA), loss of offsite power, and other postulated accidents including a line rupture with a radioactive release inside the auxiliary building.

The ESF room cooler and safety-related chiller system is required to automatically start when the systems or components it supports are, or may be, required to operate following an SI or CRI signal. The system is designed to perform its function with a single failure of any active component, assuming the loss of offsite power. One train of the ESF room cooler and safety-related chiller system provides 100% of the required cooling for the associated train of ESF equipment.

The ESF room cooler and safety-related chiller system satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

LCO

Two ESF room cooler and safety-related chiller system trains are required OPERABLE to provide the required redundancy to ensure that the system functions to remove heat from the ESF equipment rooms during and after an accident assuming the worst case single failure occurs coincident with the loss of offsite power.

The recirculating fan coolers that service the spent fuel heat exchanger and pump rooms are not within the scope of this LCO. The spent fuel pool cooling and purification system (SFPCPS) is highly desirable but not required to maintain the integrity of the spent fuel stored in the pool. In the unlikely event that both trains of the SFPCPS were to fail, the result would be an increase in the temperature of the water in the pool, and pool water inventory can be made up indefinitely. Therefore, the coolers serving the SFPCPS equipment rooms are highly desirable but not required.

An ESF room cooler and safety-related chiller system train is considered OPERABLE when:

a. Each required fan cooler unit including fan, cooling coils, and instrumentation required to perform the safety-related function is OPERABLE; and

(continued)

BASES

LCO (continued)

b. The associated chilled water system, including the chiller, water pump, piping, valves, and instrumentation required to perform the safety-related function is OPERABLE.

The LCO is modified by a Note that allows one safety-related chiller train to be removed from service for up to 2 hours under administrative controls for surveillance testing of the other chiller train. This note is required to allow surveillance testing to be performed separately on each safety-related chiller train. Such testing may include individual automatic starts of each chiller train. Administrative controls must be in place to ensure the train removed from service can be rapidly returned to service if the need arises. When this note is utilized, the train removed from service is not required OPERABLE during the testing of the other train.

APPLICABILITY

In MODES 1, 2, 3, and 4, the ESF room cooler and safety-related chiller system must be OPERABLE to provide a safety-related cooling function consistent with the OPERABILITY requirements of the ESF equipment it supports. In MODES 5 or 6, there are no TS OPERABILITY requirements for the ESF room cooler and safety-related chiller system. However, the functional requirements of the ESF room cooler and safety-related chiller system to provide supplemental cooling for normal HVAC are determined by the systems it supports. In these MODES, any supplemental cooling provided by the ESF room cooler and safety-related chiller system is not a required safety function of the system.

ACTIONS

A.1

If one ESF room cooler and safety-related chiller system train is inoperable, action must be taken to restore the train to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE ESF room cooler and safety-related chiller system train is adequate to perform the heat removal function for its associated ESF equipment.

However, the overall reliability is reduced because a single failure in the OPERABLE ESF room cooler and safety-related chiller system train could result in loss of the ESF room cooler and safety-related chiller system function. 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. Alternatively, a Completion Time can be

(continued)

BASES

ACTIONS

A.1 (continued)

determined in accordance with the Risk Informed Completion Time Program (Ref. 3).

B.1

With two ESF room cooler and safety-related chiller trains inoperable, the system may be incapable of maintaining the required air temperatures in rooms containing safety-related equipment during and after design basis events. Consequently, one hour is provided to return one ESF room cooler and safety-related trains to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The CONDITION is modified by two Notes. The first Note states it is not applicable when the second ESF train is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is intended only when the second ESF train is found inoperable with one train already inoperable, or if two ESF trains are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours (Ref. 3).

C.1 and C.2

If the ESF room cooler and safety-related chiller 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 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 3.7.14.1

Verifying the correct alignment for manual, power operated, and automatic valves servicing safety-related equipment provides assurance that the proper flow paths exist for ESF room cooler and safety-related chiller system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1 (continued)

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 3.7.14.2

This SR verifies proper automatic operation of the ESF room cooler and safety-related chiller system valves servicing safety-related equipment on an actual or simulated actuation signal. The safety-related chiller trains are also required to operate on a CRI 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.

SR 3.7.14.3

This SR verifies proper operation of the ESF room cooler and safety-related chiller system fans and pumps on an actual or simulated actuation signal. The safety-related chiller system is also required to automatically start on a CRI signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Section 7.3.

2. FSAR, Section 9.4.

3. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

B 3.7 PLANT SYSTEMS

B 3.7.15 Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the fuel storage 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 fuel storage pool design is given in the FSAR, Subsection 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the FSAR, Subsection 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the FSAR, Subsection 15.7.4 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.195 (Ref. 4). The resultant 2 hour thyroid dose per person at the exclusion area boundary is a small fraction of the 10 CFR 100 (Ref. 5) limits.

According to Reference 4, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool 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 this 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 top of the fuel bundle and the surface, indicated by 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 analyses also assume a limited number of fuel rods are damaged in a second fuel bundle.

The fuel storage pool water level satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

LCO	The fuel storage 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 fuel storage pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.15.1</u> This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1 (continued)

water level in the fuel storage pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

During refueling operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.7.1.

REFERENCES

1. FSAR, Subsection 9.1.2.
2. FSAR, Subsection 9.1.3.
3. FSAR, Subsection 15.7.4.
4. Regulatory Guide 1.195, May 2003.
5. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.16 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 2 hour thyroid dose to a person at the exclusion area boundary (EAB) would be about 0.58 rem if the main steam safety valves (MSSVs) open for 2 hours following a trip from full power.

Operating a unit at the allowable limits could result in a 2 hour EAB exposure of a small fraction of the 10 CFR 100 (Ref. 1) limits.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 15 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 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 a small fraction of the unit EAB limits (Ref. 1) for whole body and thyroid dose rates. 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 atmospheric dump valves (ARVs). 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 generator is assumed to discharge steam and any entrained activity through the MSSVs and ARVs during the event. Since no credit is taken in the analysis for activity plateout 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).
LCO	As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (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

(continued)

BASES

LCO (continued)	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 cannot be restored to within limits 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 unit systems.
SURVEILLANCE REQUIREMENTS	SR 3.7.16.1 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.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 100.11.
2. FSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.17 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

Fuel assemblies are stored in high density racks. The Unit 1 spent fuel storage racks contain storage locations for 1476 fuel assemblies, and the Unit 2 spent fuel storage racks contain storage locations for 2098 fuel assemblies. The Unit 1 racks use boral as a neutron absorber in a flux trap design. The Unit 2 racks contain Boraflex, however, no credit is taken for Boraflex. Westinghouse 17x17 fuel assemblies with initial enrichments of up to and including 5.0 weight percent U-235 can be stored in any location in the Unit 1 or Unit 2 fuel storage pool provided the fuel burnup-enrichment combinations are within the limits that are specified in Figures 3.7.18-1 (Unit 1) or 3.7.18-2 (Unit 2) of the Technical Specifications. Fuel assemblies that do not meet the burnup-enrichment combination of Figures 3.7.18-1 or 3.7.18-2 may be stored in the storage pools of Units 1 or 2 in accordance with checkerboard storage configurations described in Figures 4.3.1-1 through 4.3.1-10. The acceptable fuel assembly storage configurations are based on NRC-approved acceptance criteria for crediting soluble boron as described in the NRC's safety evaluation report in WCAP-14416-P-A (Reference 4).

The Westinghouse Spent Fuel Rack Criticality Methodology ensures that the multiplication factor, K_{eff}, of the fuel and spent fuel storage racks is less than or equal to 0.95 as recommended by ANSI 57.2-1983 (Reference 3) and NRC guidance (References 1, 2 and 6). The codes, methods, and techniques contained in the methodology are used to satisfy this criterion on K_{eff}.

The analysis methodology employs: (1) SCALE-PC, a personal computer version of the SCALE-4.3 code system, with the updated SCALE-4.3 version of the 44 group ENDF/B-V neutron cross section library, and (2) the two-dimensional integral transport code DIT with an ENDF/B-VI neutron cross section library.

SCALE-PC was used for calculations involving infinite arrays for the "2-out-of-4", "3-out-of-4", "All-Cell", and "3x3" fuel assembly storage configurations. In addition, it was employed in a full pool representation of the storage racks to evaluate soluble boron worth and postulated accidents.

SCALE-PC, used in both the benchmarking and the fuel assembly storage configurations, includes the control module CSAS25 and the following functional modules: BONAMI, NITAWL-II, and KENO V.a.

(continued)

BASES

BACKGROUND (continued)

The DIT code is used for simulation of in-reactor fuel assembly depletion. KENO V.a was used in the calculation of biases and uncertainties.

Reference 4 describes how credit for fuel storage pool soluble boron is used under normal storage configuration conditions. The storage configuration is defined using K_{eff} calculations to ensure that the K_{eff} will be less than 1.0 with no soluble boron under normal storage conditions including tolerances and uncertainties. Soluble boron credit is then used to maintain K_{eff} less than or equal to 0.95. The analyses assumed 19.9% of the boron atoms have atomic weight 10 (B-10). However, to account for the effects of variations in the natural abundance of B-10, the calculated boron concentrations, as well as the concentrations for accidents, were adjusted to correspond to a B-10 fraction of 19.7%. The Unit 1 pool requires 511 ppm and the Unit 2 pool requires 394 ppm to maintain K_{eff} less than or equal to 0.95 for all allowed combinations of storage configurations, enrichments, and burnups.

This methodology was used to evaluate the storage of fuel with initial enrichments up to and including 5.0 weight percent U-235 in the Vogtle fuel storage pools. The resulting enrichment, and burnup limits for the Unit 1 and Unit 2 pools, respectively, are shown in Figures 3.7.18-1 and 3.7.18-2. Checkerboard storage configurations are defined to allow storage of fuel that is not within the acceptable burnup domain of Figures 3.7.18-1 and 3.7.18-2. These storage requirements are shown in Figures 4.3.1-1 through 4.3.1-10. A boron concentration of 2000 ppm assures that no credible dilution event will result in a K_{eff} of > 0.95.

APPLICABLE SAFETY ANALYSES

The soluble boron concentration, in units of ppm, required to maintain K_{eff} less than or equal to 0.95 under accident conditions is determined by first surveying all possible events which increase the K_{eff} value of the spent fuel pool. The accident event which produced the largest increase in spent fuel pool K_{eff} value is employed to determine the required soluble boron concentration necessary to mitigate this and all less severe accident events. The list of accident cases considered includes:

- Dropped fresh fuel assembly on top of the storage racks,
- Misloaded fresh fuel assembly into an incorrect storage rack location,
- Misloaded fresh fuel assembly outside of the storage racks,

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Reduction in rack module-to-module water gap due to seismic event,
- Spent fuel pool temperature outside the normal range of 50 °F to 185 °F.

From a criticality standpoint, a dropped assembly accident occurs when a fuel assembly in its most reactive condition is dropped onto the storage racks. The rack structure from a criticality standpoint is not excessively deformed. Previous accident analysis with unborated water showed that the dropped assembly which comes to rest horizontally on top of the rack has sufficient water separating it from the active fuel height of stored assemblies to preclude neutronic interaction. For the borated water condition, the interaction is even less since the water contains boron, an additional thermal neutron absorber.

Several fuel mishandling events were simulated with KENO V.a to assess the possible increase in the K_{eff} value of the spent fuel pools. The fuel mishandling events all assumed that a fresh Westinghouse OFA fuel assembly enriched to 5.0 $^{w}/_{o}$ ^{235}U (and no burnable poisons) was misloaded into the described area of the spent fuel pool. These cases were simulated with the KENO V.a model for the entire spent fuel pool.

For Unit 1, the fuel mishandling event which produced the largest increase in spent fuel pool K_{eff} value is the misloading of a fresh fuel assembly between a “3-out-of-4” fuel assembly storage configuration and the pool wall. The additional soluble boron concentration necessary to mitigate this and all less severe accident events is 340 ppm.

For Unit 2, the fuel mishandling event which produced the largest increase in spent fuel pool K_{eff} value is the misloading of a fresh fuel assembly in an incorrect storage rack location for the “2-out-of-4” configuration. The additional soluble boron concentration necessary to mitigate this and all less severe accident events is 704 ppm.

For the accident due to a seismic event, the gap between rack modules was reduced to zero. For both Units 1 and 2, the reactivity increase is an order of magnitude less than that for the fuel mishandling events.

An increase in the temperature of the water passing through the stored fuel assemblies causes a decrease in water density which results in an addition of negative reactivity for flux trap design racks such as the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Unit 1 racks. However, since Boraflex is not considered to be present for the Unit 2 racks and the fuel storage pool water has a high concentration of boron, a density decrease causes a positive reactivity addition. The reactivity effects of a temperature range from 32° F to 240° F were evaluated. This bounds the temperature range assumed in the criticality analyses (50° F to 185° F). The increase in reactivity due to the decrease in temperature below 50° F is bounded by the misplacement of a fuel assembly between the rack and pool walls for the Unit 1 racks. The increase in reactivity due to the increase in temperature is bounded by the misload accident, for the Unit 2 racks.

Including the effects of accidents, the maximum required boron concentration to maintain $K_{eff} \leq 0.95$ is 851 ppm for Unit 1 and 1098 ppm for Unit 2 which is well below the limit of 2000 ppm.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).

LCO

The fuel storage pool boron concentration is required to be $\geq$ 2000 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential criticality accident scenarios as described in reference 5. The amount of soluble boron required to offset each of the above postulated accidents was evaluated for all of the proposed storage configurations. That evaluation established the amount of soluble boron necessary to ensure that K_{eff} will be maintained less than or equal to 0.95 should pool temperature exceed the assumed range or a fuel assembly misload occur. The amount of soluble boron necessary to mitigate these events was determined to be 851 ppm for Unit 1 and 1098 ppm for Unit 2. The specified minimum boron concentration of 2000 ppm assures that the concentration will remain above these values. In addition, the boron concentration is consistent with the boron dilution evaluation that demonstrated that any credible dilution event could be terminated prior to reaching the boron concentration for a K_{eff} of > 0.95. These values are 511 ppm for Unit 1 and 394 ppm for Unit 2.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel storage pool.

(continued)

BASES (continued)

ACTIONS

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

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the fuel storage 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. Immediate action to restore the concentration of boron is also required simultaneously with suspending movement of fuel assemblies. This does not preclude movement of a fuel assembly to a safe position If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

This SR verifies that the concentration of boron in the fuel storage 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. The gate between the Unit 1 and Unit 2 fuel storage pool is normally open. When the gate is open the pools are considered to be connected for the purpose of conducting the surveillance.

REFERENCES

1. USNRC Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition. NUREG-0800, June 1987.

2. USNRC Spent Fuel Storage Facility Design Bases (for Comment) Proposed Revision 2, 1981. Regulatory Guide 1.13.

3. ANS, "Design Requirements for Light Water Reactor Spent Fuel Storage Facilities at Nuclear Power Stations," ANSI/ANS-57.2-1983.

(continued)

BASES

REFERENCES (continued)

4. WCAP-14416 NP-A, Rev. 1, "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," November 1996.

5. Vogtle FSAR, Section 4.3.2.

6. Nuclear Regulatory Commission, Letter to All Power Reactor Licensees from B. K. Grimes, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," April 14, 1978.

B 3.7 PLANT SYSTEMS

B 3.7.18 Fuel Assembly Storage in the Fuel Storage Pool

BASES

BACKGROUND

The Unit 1 spent fuel storage racks contain storage locations for 1476 fuel assemblies, and the Unit 2 spent fuel storage racks contain storage locations for 2098 fuel assemblies.

Westinghouse 17X17 fuel assemblies with an enrichment of up to and including 5.0 weight percent U-235 can be stored in the acceptable storage configurations that are specified in Figures 3.7.18-1 (Unit 1), 3.7.18-2 (Unit 2), and 4.3.1-1 through 4.3.1-10. The acceptable fuel assembly storage configurations are based on NRC-approved acceptance criteria for crediting soluble boron as described in the NRC's safety evaluation report in WCAP-14416-P-A (Reference 1). Additional background discussion can be found in B 3.7.17.

Westinghouse 17x17 fuel assemblies with nominal enrichments no greater than 3.556 w/o^{235}U may be stored in all storage cell locations of the Unit 1 pool. Fuel assemblies with initial nominal enrichment greater than 3.556 w/o^{235}U must satisfy a minimum burnup requirement as shown in Figure 3.7.18-1 or a minimum Integral Fuel Burnable Absorber (IFBA) requirement as shown in Figure 4.3.1-7.

Westinghouse 17x17 fuel assemblies with nominal enrichments no greater than 5.0 w/o^{235}U may be stored in a 3-out-of-4 checkerboard arrangement with empty cells in the Unit 1 pool. There are no minimum burnup requirements for this configuration.

Westinghouse 17x17 fuel assemblies with nominal enrichments no greater than 1.73 w/o^{235}U may be stored in all storage cell locations of the Unit 2 pool. Fuel assemblies with initial nominal enrichment greater than 1.73 w/o^{235}U must satisfy a minimum burnup requirement as shown in Figure 3.7.18-2.

Westinghouse 17x17 fuel assemblies with nominal enrichments no greater than 2.40 w/o^{235}U may be stored in a 3-out-of-4 checkerboard arrangement with empty cells in the Unit 2 pool. Fuel assemblies with initial nominal enrichment greater than 2.40 w/o^{235}U must satisfy a minimum burnup requirement as shown in Figure 4.3.1-8.

(continued)

BASES

BACKGROUND (continued)	Westinghouse 17x17 fuel assemblies with nominal enrichments no greater that 5.0 w/o^{235}U may be stored in a 2-out-of-4 checkerboard arrangement with empty cells in the Unit 2 pool. There are no minimum burnup requirements for this configuration. Westinghouse 17x17 fuel assemblies may be stored in the Unit 2 pool in a 3x3 array. The center assembly must have an initial enrichment no greater than 3.20 w/o^{235}U or satisfy a minimum IFBA requirement for higher initial enrichments as shown in Figure 4.3.1-9. The surrounding fuel assemblies must have an initial nominal enrichment no greater than 1.39 w/o^{235}U or satisfy a minimum burnup and decay time requirement for higher initial enrichments as shown in Figure 4.3.1-10.
APPLICABLE SAFETY ANALYSIS	Most fuel storage pool accident conditions will not result in an increase in K_{eff}. However, accidents can be postulated for each storage configuration which could increase reactivity beyond the analyzed condition. A discussion of these accidents is contained in B 3.7.17. The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
LCO	The restrictions on the placement of fuel assemblies within the fuel storage pool ensure the K_{eff} of the fuel storage pool will always remain < 0.95, assuming the pool to be flooded with borated water. The combination of initial enrichment and burnup are specified in Figures 3.7.18-1 and 3.7.18-2 for all cell storage in the Unit 1 and Unit 2 pools, respectively. Other acceptable enrichment-burnup, enrichment-IFBA, and checkerboard combinations are described in Figures 4.3.1-1 through 4.3.1-10.
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the fuel storage pool.

(continued)

BASES (continued)

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the configuration of fuel assemblies stored in the fuel storage pool is not in accordance with the acceptable combination of initial enrichment, burnup, and storage configurations, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with Figures 3.7.18-1 (Unit 1), 3.7.18-2 (Unit 2), or Specification 4.3.1.1 (Unit 1) or 4.3.1.2 (Unit 2).

If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.18.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is within the acceptable burnup domain of Figures 3.7.18-1 (Unit 1) or 3.7.18-2 (Unit 2). For fuel assemblies in the unacceptable range of Figures 3.7.18-1 and 3.7.18-2, performance of this SR will also ensure compliance with Specification 4.3.1.1 (Unit 1) or 4.3.1.2 (Unit 2).

Fuel assembly movement will be in accordance with preapproved plans that are consistent with the specified fuel enrichment, burnup, and storage configurations. These plans are administratively verified prior to fuel movement. Each assembly is verified by visual inspection to be in accordance with the preapproved plan prior to storage in the fuel storage pool. Storage commences following unlatching of the fuel assembly in the fuel storage pool.

REFERENCES

1. WCAP-14416-NP-A, Revision 1, "Westinghouse Spent Fuel Rack Criticality Analysis Methodology," November 1996.

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 (preferred power sources, normal and alternate(s)), 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 (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a single DG.

Offsite power is supplied to the unit switchyard from the transmission network by eight transmission lines. From the switchyard, two electrically and physically separated circuits provide AC power, normally through step down reserve auxiliary transformers (RATS), to the 4.16 kV ESF buses. In addition to the two offsite circuits described above, the 13.8 kV standby auxiliary transformer (SAT) provides an additional qualified offsite source. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the FSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network or the 13.8 kV SAT to the onsite Class 1E ESF bus(es).

The offsite power circuit which provides AC power through the SAT feeds the SAT through a direct buried cable. The buried cable originates at Georgia Power Company's Plant Wilson and can be powered by either the 230 kV grid system or from any combination of the Plant Wilson's (6) 60 MVA units of combustion turbine electrical generators. Both

(continued)

BASES

BACKGROUND (continued)

methods of supplying power utilize the Plant Wilson switchyard 13.8 kV power system. Two of the Plant Wilson combustion turbines have an enhanced black start capability (can be started without offsite power). The SAT is a "swing" or common offsite power source capable of connecting to any safety bus on either unit.

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs A and B are dedicated to ESF buses A and B, respectively. A DG starts automatically on a safety injection (SI) signal 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, in response to the undervoltage signal, a sequencer 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 the automatic load sequencer. 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 preferred 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 returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating

(continued)

BASES

BACKGROUND (continued)

signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to 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 7000 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.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, 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 unit. This results in maintaining at least one train 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; 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 between the 230 kV grid system and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a

(continued)

BASES

LCO (continued)

safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

In addition, one required automatic load sequencer per train must be OPERABLE. The automatic load sequencers are required to provide the system response to both an SI signal and a loss of or degraded ESF bus voltage condition.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

Offsite circuit #1 and #2 each consist of a RAT fed from separate lines from the 230 kV switchyard. Each RAT can supply either 4160 V ESF bus. In addition to these circuits, there is also a 13.8/4.16 kV SAT which may be manually connected to supply power to any one of the 4.16 kV ESF buses for Units 1 and 2 in place of any RAT. The SAT receives power from the Georgia Power Company Plant Wilson switchyard.

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 11.5 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 in standby with the engine hot and DG in standby with the 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 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 train must be separate and independent (to the extent possible) of the AC sources in the other

(continued)

BASES

LCO (continued)

train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus while the bus is being transferred to the other circuit.

APPLICABILITY

The AC sources and sequencers 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."

ACTIONS

A Note prohibits the application of LCO 3.0.4b 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 3.0.4b, 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 offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite 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 a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition D, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown.

These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps. Single train systems, such as turbine driven auxiliary feedwater pumps, may not be included.

The Completion Time for Required Action A.2 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. The train has no offsite power supplying its loads; and

b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the

(continued)

BASES

ACTIONS

A.2 (continued)

inoperable required feature. Additionally, the 24 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.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one required offsite 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 unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit 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. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15).

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite 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 circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 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 redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. This includes motor

(continued)

BASES

ACTIONS

B.2 (continued)

driven auxiliary feedwater pumps. Single train systems, such as turbine driven auxiliary feedwater pumps, are not included. 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.2 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 train (Train A or Train B) 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.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, 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 offsite 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.

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BASES

ACTIONS (continued)

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. 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 E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 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.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the applicable plant procedures will continue to require the evaluation of the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

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 plant corrective action program.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue for a period not to exceed 72 hours.

In Condition B, the remaining OPERABLE DG and offsite circuits 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.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15).

(continued)

BASES

ACTIONS
(continued)

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant required features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included in the list. The Completion Time for this failure of redundant safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included in the list. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate.

The Completion Time for Required Action C.1 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. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

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BASES

ACTIONS

C.1 and C.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15). This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite 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 offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15).

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

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 D are modified by a Note to indicate that when Condition D is entered with no AC source to one or more trains, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems — Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D 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 (Ref. 15).

In Condition D, 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 C (loss of both required offsite circuits). 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 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 for both Conditions D.1 and D.2 (Ref 15).

E.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

(continued)

BASES

ACTIONS

E.1 (continued)

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, however, 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.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15).

The CONDITION is modified by two Notes. The first Note states that it is not applicable when the second DG is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one DG is inoperable for any reason and the second DG is found to be inoperable, or if both DGs are found inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours.

F.1

The sequencer(s) is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. The sequencers are required to provide the system response to both an SI signal and a loss of or degraded ESF bus voltage signal. Therefore, loss of an ESF bus sequencer affects every major ESF system in the train. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

(continued)

BASES

ACTIONS

F.1 (continued)

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 15).

G.1 and G.2

If the Required Actions of Condition A, B, C, D, E, or F cannot be met within the required Completion Times, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 14). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 14, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action G.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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.

(continued)

BASES

ACTIONS (continued)

H.1

With three or more required AC sources inoperable the Required Action is to restore enough of the required inoperable AC sources to OPERABLE status within 1 hour to regain some level of redundancy in the AC electrical power supplies. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of sufficient AC electrical power supplies. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The CONDITION is modified by two Notes. The first Note states it is not applicable when three or more required AC sources are intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if two required AC sources are inoperable for any reason and a third becomes inoperable, or if three AC sources are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO can be no longer than 24 hours (Ref. 15).

I.1 and I.2

If the Required Action of Condition H cannot be completed 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.

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. 8). 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 accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10), as addressed in the FSAR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3750 V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), 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 4330 V will limit the 480 V bus voltage to within the maximum operating voltage specified for 460 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 460 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.

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.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 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 recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start 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 Note 3.

SR 3.8.1.7 requires that the DG starts from standby conditions and achieves required voltage and frequency within 11.4 seconds. The 11.4 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

The 11.4 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used.

If a modified start is not used, the 11.4 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 11.4 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 the intent of Note 1 of SR 3.8.1.2.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Any change in the scope or frequency of SR 3.8.1.2 or SR 3.8.1.7 requires reevaluation of STI Evaluation number 417332, in accordance with the Surveillance Frequency Control Program.

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, while minimizing the time that the DG is connected to the offsite source.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. 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. Any change in the scope or frequency of SR 3.8.1.3 requires reevaluation of STI Evaluation number 417332, in accordance with 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, do not invalidate this test. The lower limit of the load band ensures the DG is sufficiently loaded during the test and the upper limit of the load band is to avoid an overload condition during routine testing. The upper and lower limits provide a reasonable band to operate the DG in for the specified run time while achieving the intent of a full-load. The Note recognizes that there are external grid conditions that can cause a shift in load sharing with the DG and allows the operator time to recognize and adjust load back into the band without invalidating the performance of the surveillance. It also allows for momentary transients where the DG governor system acts to bring the load back into the load band. Momentary DG load “spikes” which are beyond the ability of the operator to monitor and control with normal control room instrumentation, and which the governor acted to maintain the proper DG load do not invalidate the test and the DG can be considered to have met the intent of operating “at full rated load” for the specified duration. Similarly, momentary power factor transients above the limit 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.

(continued)

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 required level (650 gallons). 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.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

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 load is an Auxiliary Feedwater pump motor rated at 900 horsepower. The motor is capable of demanding 962 horsepower under the most severe accident conditions. This amounts to a maximum of an 800kW demand. This surveillance may be accomplished by: 1) Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest load while paralleled to offsite power, or while solely supplying the bus, or 2) Tripping the associated single largest load with the DG solely supplying the bus. As required by IEEE-308 (Ref. 12), 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, or 15% above synchronous speed, whichever is lower.

The time, 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 upper voltage limit (SR 3.8.1.8.b) associated with the DG operating in parallel with the grid is based on the operation of the droop circuit and its potential to increase the stabilizing voltage by as much as 5% over the maximum starting voltage of 4330 V. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.8.a corresponds to the maximum frequency excursion, while SR 3.8.1.8.b and SR 3.8.1.8.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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible when synchronized to offsite power, testing must be performed using a power factor as close as practicable to ≤ 0.9 while maintaining voltage ≤ 4330 V. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. The voltage limit of 4330 V is required to prevent operation of any loads at or above the maximum design voltage.

This SR is modified by a Note. The Note acknowledges that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.9

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 load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a kVAR load as close as practicable to 3390 kVAR while maintaining voltage ≤ 4330 V. This kVAR load is chosen to be representative of the actual design basis inductive loading that the DG would experience. The voltage limit of 4330 V is required to prevent operation of any loads at or above the maximum design voltage.

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

This SR is been modified by a Note. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.10

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

The DG autostart time of 11.4 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. An additional tenth of a second is allowed for energizing permanently connected loads, thus the 11.5 second requirement in this surveillance. 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, Emergency Core Cooling Systems (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.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.11

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (11.4 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.11.d and SR 3.8.1.11.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection 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 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 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.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.12

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.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.13

This Surveillance Requirement demonstrates that the DGs can start and run continuously at loads in excess of the maximum expected loading for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to ≥ 105% of the maximum expected loading and the remainder of the time at a load equivalent to the maximum expected loading of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a kVAR load as close as practicable to 3390 kVAR while loaded ≥ 6500 kW and maintaining voltage ≤ 4330 V. This kVAR load is chosen to be representative of the actual design basis inductive loading that the DG would experience. The voltage limit of 4330 V is required to prevent operation of any loads at or above the maximum design voltage. 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 frequency of performing SR 3.8.1.13 was changed from 18 months to 24 months to follow diesel generator teardown inspections which were performed on a 24-month frequency. The teardown frequency has since been extended to 36 months by the Owners' Group Maintenance Program based on satisfactory inspection results. Since the 24-month frequency of performing this surveillance does not coincide with the present diesel generator inspection frequency, this surveillance will be performed on an 18-month frequency such that alternate surveillances will continue to follow diesel generator teardown inspections. The 24-month

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

frequency is retained for this surveillance requirement since the diesel generator Owners' Group Maintenance Program is considered to be a "living" program subject to future changes. Any future changes could either extend or reduce inspection frequencies which could again make the 24-month frequency of this surveillance requirement coincide with the teardown frequency.

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

This Surveillance is modified by two Notes. Note 1 states that momentary transients do not invalidate this test. The lower limit of the load band ensures the DG is sufficiently loaded during the test and the upper limit of the load band is to avoid an overload condition during routine testing. The upper and lower limits provide a reasonable band to operate the DG in for the specified run time while achieving the intent of a full-load. The Note recognizes that there are external grid conditions that can cause a shift in load sharing with the DG and allows the operator time to recognize and adjust load back into the band without invalidating the performance of the surveillance. It also allows for momentary transients where the DG governor system acts to bring the load back into the load band. Momentary DG load "spikes" which are beyond the ability of the operator to monitor and control with normal control room instrumentation, and which the governor acted to maintain the proper DG load do not invalidate the test and the DG can be considered to have met the intent of operating "at full rated load" for the specified duration. Similarly, momentary kVAR load transients above the limit will not invalidate the test.
Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available.

SR 3.8.1.14

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 11.4 seconds. The 11.4 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. 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. Momentary transients do not invalidate this test. The lower limit of the load band ensures the DG is sufficiently hot and the upper limit of the load band is to avoid an overload condition during routine testing. The upper and lower limits provide a reasonable band to operate the DG in for the specified run time. The Note recognizes that there are external grid conditions that can cause a shift in load sharing with the DG and allows the operator time to recognize and adjust load back into the band without invalidating the performance of the surveillance. It also allows for momentary transients where the DG governor system acts to bring the load back into the load band. Momentary DG load "spikes" which are beyond the ability of the operator to monitor and control with normal control room instrumentation, and which the governor acted to maintain the proper DG load band do not invalidate the test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.15

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and automatic 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. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.16

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. 11), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.11. The intent in the requirement associated with SR 3.8.1.16.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.

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. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.17

Under accident and loss of offsite power conditions, loads are sequentially connected to the bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the 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. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

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 3.8.1.10, 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.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.19

This surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to the other train's associated day tank via installed crossconnect

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

lines. This capability is required to support continuous operation of standby power sources. This surveillance provides assurance that the fuel oil transfer pump is OPERABLE and the fuel oil transfer crossconnect piping is intact and not obstructed. The Surveillance Frequency is controlled under the Surveillance Frequency Control. The Frequency takes into consideration the additional monthly testing required of each fuel oil transfer system train to automatically supply its own day tank and the passive nature of the crossconnect piping.

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.

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.

(continued)

BASES

REFERENCES (continued)

10. Regulatory Guide 1.137, Rev. 1, October 1979.

11. IEEE Standard 308-1978.

12. Generic Letter 91-04, "Changes in Technical Specification Intervals to Accommodate a 24-Month Fuel Cycle," April 2, 1991.

13. STI Evaluation 417332.

14. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010

15. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

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 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.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 MODE 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.

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).

LCO

One offsite 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 powered from offsite power. An OPERABLE DG, associated with a distribution system train 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

(continued)

BASES

LCO (continued)

offsite circuit. Together, OPERABILITY of the required offsite 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 offsite 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 offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

Offsite circuits #1 and #2 each consist of a RAT fed from separate lines from the 230 kV switchyard. Each RAT can supply either 4160 V ESF bus. In addition to these circuits, there is also a 13.8/4.16 kV SAT which may be manually connected to supply power to either 4160 V ESF bus and replace either RAT. The SAT receives power from the Georgia Power Company Plant Wilson switchyard.

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 11.5 seconds. The DG must be capable of accepting the required loads manually, 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 standby with the engine hot and DG in standby with the engine at ambient conditions.

Proper sequencer operation to support the DG auto-start on loss of power and degraded grid voltage, including tripping of nonessential loads, is a required function for DG OPERABILITY. Automatic load sequencing is not required in MODES 5 or 6.

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

(continued)

BASES (continued)

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Systems needed to mitigate a fuel handling accident are available;

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. 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

A.1

An offsite circuit would be considered inoperable if it were not available to one required ESF train. Although two trains are required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features 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.

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to all required trains, 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, and operations involving positive reactivity additions. The Required Action to suspend positive

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

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 unit 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.

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 train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

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 3.8.1.10.C.2, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.16, SR 3.8.1.17, and SR 3.8.1.18 are not required to be met because the required OPERABLE DG is not required to respond to an SI signal or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

have loads automatically sequenced on the associated ESF bus. SR 3.8.1.20 is excepted 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 deenergizing 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 are required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

The diesel generators (DG) are provided with storage tanks having a total combined fuel oil capacity sufficient to operate a diesel for a period ≥ 7 days while the DG is continuously operating at its rated capacity. The DG fuel oil and storage systems are discussed in the FSAR, Paragraph 9.5.4.2 (Ref. 1). The maximum load demand is calculated using the assumption that a minimum of any two DGs is available. 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 storage tank to day tank by either of two transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground.

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 impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. The onsite storage in addition to the engine oil sump is sufficient to ensure 7 days of continuous operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has two redundant 100% capacity air start systems with adequate capacity for five successive start attempts each on the DG without recharging the air start receiver(s).

(continued)

BASES

BACKGROUND (continued)

Each DG building contains two ventilation supply fans and associated dampers. The ventilation supply fans are required to limit the DG building air temperature to ≤ 120° F to support the operation of the associated DG. The fans in each DG building and associated dampers start and actuate on different signals. Fans 1/2-1566-B7-001 (train A) and 1/2-1566-B7-002 (train B) start automatically and the necessary intake and discharge dampers actuate to the correct position on a train associated DG running signal and fans 1/2-1566-B7-003 and 1/2-1566-B7-004 start automatically and the necessary intake and discharge dampers actuate to the correct position on high DG building temperature signal coincident with a DG running signal.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 4), and in the FSAR, 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 diesel fuel oil, lube oil, air start, and ventilation subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Combined stored diesel fuel oil per unit is required to have sufficient supply for 7 days of full load operation of at least one diesel generator. In MODES 1, 2, 3, and 4, a capacity equivalent to 85,848 gallons (Ref. 8) is required to provide for ≥ 7 days of continuous DG operation at rated capacity. However, in MODES 5 and 6, the highest DG loading identified for either train is significantly less than the maximum post loss of coolant accident loading for MODES 1 through 4, and the capacity of one storage tank is sufficient to provide for ≥ 7 days of DG operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating

(continued)

BASES

LCO (continued)

oil supply must be available to ensure the capability to operate at full load for 7 days. 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

(continued)

BASES

LCO (continued)

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."

The requirement for sufficient fuel oil to support ≥ 7 days of operation may be met by alternative means as discussed in FSAR section 9.5.4.2.2 when performing required maintenance (draining and cleaning) of a storage tank.

The starting air system is required to have a minimum capacity for five successive DG start cycles without recharging the air start receivers.

Two DG ventilation supply fans are required OPERABLE for each DG to limit the DG building air temperature to ≤ 120° F.

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 stored diesel fuel oil, lube oil, and starting air and ventilation subsystems support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits and ventilation supply fans OPERABLE when the associated DG is required to be OPERABLE.

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 inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 5.2 day fuel oil supply in a single storage tank for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 3.9 day supply in that tank. The 3.9 day supply still allows ample time to transfer fuel from the other storage tank. These values are based on Reference 8.

(continued)

BASES

ACTIONS

A.1 (continued)

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. 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 (> 3.9 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

Note that the above discussion is applicable to MODES 1, 2, 3, and 4. In MODES 5 and 6, the highest load demand identified for the DGs is sufficiently small that a single storage tank will provide for ≥ 7 days of DG operation (Ref. 8). However, if the stored fuel oil in the required storage tank is found to be < 68,000 gallons and > 52,000 gallons during MODES 5 and 6, Condition A and Required Action A.1 continue to apply.

B.1

With lube oil inventory < 336 gal, sufficient lubricating oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. These values are based on Reference 9. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of the particulate component for stored fuel oil of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample technique (e.g., bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow

(continued)

BASES

ACTIONS

C.1 (continued)

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.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, 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.

E.1

With both starting air receiver pressures < 210 psig, sufficient capacity for five successive DG start cycles does not exist. However, as long as one receiver pressure is > 175 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while one air receiver pressure is restored to the required limit. These values are based on Reference 10. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

F.1

With one DG ventilation supply fan inoperable, the capability to maintain the DG building air temperature below the required limit is degraded. In most cases, except for extreme ambient temperatures, one DG ventilation supply fan is sufficient to maintain the DG building temperature below the limit. However, the remaining system capacity is degraded and action must be taken to restore the inoperable fan to operable status within 14 days. The Completion Time allowed is reasonable considering the redundant DG, the remaining fan capacity available for the affected DG, and the fact that an event requiring the DG to operate would have to occur combined with ambient temperatures in excess of 93°F that would require both fans to operate in the affected DG building. Furthermore, DG operation with a single ventilation supply fan combined with ambient temperatures in excess of 93°F would result in temperatures in excess of the limit by a few degrees only (commensurate with the extent to which the ambient temperature exceeds 93°F).

G.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, or one or more DGs with both required ventilation fans inoperable, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

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 one DG's operation for at least 7 days at full load. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

Note that in MODES 1, 2, 3, and 4, a capacity equivalent to 85,848 gallons (Ref. 8) is required to provide for ≥ 7 days of continuous DG operation at rated capacity. In MODES 5 and 6 only one storage tank is required to provide for ≥ 7 days DG operation.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1 (continued)

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

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available on the plant site to support at least 7 days of full load operation for each DG. The 336 gal requirement is based on the worst case DG consumption rate for full load operation (Reference 9). The 336 gallons is the volume required in excess of the recommended minimum volume required by the manufacturer. The 336 gallons may be contained in the lube oil sump tanks and the engine sump, in onsite storage, or a combination of the two. Implicit in this SR is the requirement to have the ability to transfer the lube oil from its storage location to the DG, when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

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

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. The following tests are to be performed prior to adding new fuel oil to storage tanks:

a. Sample the new fuel oil in accordance with ASTM D4057 (Ref. 6);

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

b. Verify in accordance with the tests specified in ASTM D975 (Ref. 7) that the sample has an API Gravity of within 0.3 degrees at 60°F, or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of ≥ 0.82 and ≤ 0.89 or an API gravity at 60°F of ≥ 27 degrees and ≤ 42 degrees when tested in accordance with ASTM D1298 (Ref. 6), a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, if gravity was not determined by comparison with supplier's certification, 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 or a water and sediment content within limits when tested in accordance with ASTM D2709 (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975, except that the analysis for sulfur may be performed in accordance with ASTM D1552, ASTM D2622, or ASTM D4294 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulates, due mostly to oxidation. The presence of particulates does not mean the fuel oil will not burn properly in a diesel engine. The particulates 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. 6) which provides for obtaining a field sample and subsequent laboratory testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

The particulate concentration limit is 10 mg/l. Each tank must be considered and tested separately.

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 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. The duration of each start cycle is about 3 seconds or two to three engine revolutions. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished. (PI-9060, PI-9061, PI-9064, PI-9065)

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

SR 3.8.3.5

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 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.5 (continued)

regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.6

This surveillance demonstrates that each DG ventilation supply fan starts automatically and the necessary dampers actuate to the correct position on a simulated or actual actuation signal. The two fans in each DG building and associated dampers start and actuate on different signals. Fans 1/2-1566-B7-001 (train A) and 1/2-1566-B7-002 (train B) start automatically and the necessary intake and discharge dampers actuate to the correct position on a train associated DG running signal and fans 1/2-1566-B7-003 and 1/2-1566-B7-004 start automatically and the necessary intake and discharge dampers actuate to the correct position on high DG building temperature signal coincident with a DG running signal.

(continued)

BASES (continued)

REFERENCES

1. FSAR, Paragraph 9.5.4.2.

2. Regulatory Guide 1.137.

3. ANSI N195-1976, Appendix B.

4. FSAR, Chapter 6.

5. FSAR, Chapter 15.

6. ASTM Standards: D4057-06; D1298-06; D4176-04; D1552-07; D2622-07; D4294-08a; D5452-08; D2709-96.

7. ASTM Standards, D975-07.

8. Southern Company Services Calculation number X4C2403V08, Standby Diesel Generator Fuel Oil Consumption and Storage Tank Capacity.

9. Southern Company Services Calculation numbers X4C2403V11 and X4C2403V12, Emergency Diesel Generator Lube Oil Inventory Technical Specification Values.

10. Southern Company Services Calculation number X4C2403V09, Emergency Diesel Generator Starting Air Pressure Technical Specification Value.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources — Operating

BASES

BACKGROUND

There are four safety features 125 VDC systems (identified A, B, C, and D) per unit. Each system has a 59-cell lead calcium battery, switchgear (electrically operated drawout circuit breakers), two redundant battery chargers, and 125 VDC distribution panels (molded case circuit breakers). Systems A, B, and C each have a 125 VDC motor control center for motor operated valves. There is no capability to connect the DC systems between themselves, between Unit 1 and Unit 2 systems, or between the safety features systems and the nonsafety features systems. Table B 3.8.4-1 shows the DC sources and train associations. The 125 VDC systems A and C form the train A safety features DC system and their associated battery chargers receive power from two Class 1E train A motor control centers. The 125 VDC systems B and D form the train B safety features DC system and their battery chargers receive power from two Class 1E train B motor control centers.

The 125 VDC systems A, B, C, and D supply DC power to channels 1, 2, 3, and 4, respectively, and are designated as Class 1E equipment in accordance with the applicable sections of Institute of Electrical and Electronic Engineers (IEEE) Standard 308 (Ref. 1). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 2), the DC electrical power system is designed so that no single failure in any 125 VDC system will result in conditions that will prevent the safe shutdown of the reactor plant. The plant design and circuit layout from these DC systems provide physical separation of equipment, cabling, and instrumentation essential to plant safety. Each 125 VDC battery is separately housed in a ventilated room apart from its chargers and distribution equipment. All the components of the 125 VDC Class 1E systems are housed in Category 1 structures.

During normal operation the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery chargers, the DC load is automatically powered from the batteries.

(continued)

BASES

BACKGROUND (continued)

Batteries are sized in accordance with IEEE 485 (Ref. 3) to have sufficient capacity to supply the required loads for a loss of coolant/ loss of offsite power (LOCA/LOSP) duration of 2 3/4 hours and a station blackout (SBO) duration of 4 hours. For LOSP/LOCA, they are sized at a minimum temperature of 70°F; their initial capacity was increased by 10% for load growth and 25% for aging. The required final (end of duty cycle and end of life) battery cell voltages for each load group have been analyzed to demonstrate that adequate voltage is provided to the loads. The battery voltage specifications are discussed in detail for each load group in FSAR, Chapter 8 (Ref. 4).

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 121.8 V for a 59 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 2.23 Vpc corresponds to a total float voltage output of 131.6 V for a 59 cell battery as discussed in the FSAR, Chapter 8 (Ref. 4).

Each 125 VDC battery is provided with two battery chargers, each of which is sized to supply the continuous (long term) demand on its associated DC system while providing sufficient power to replace 110% of the equivalent ampere-hours removed from the battery during a design basis battery discharge cycle within a 12 hour period after charger input power is restored. If desired to operate with both battery chargers online, load sharing circuitry is provided to ensure that the DC load is properly shared between the two chargers. Only one charger is required OPERABLE to support the associated DC power system. The sizing of each battery charger meets the requirements of IEEE 308 (Ref. 1) and Regulatory Guide 1.32 (Ref. 5).

The in-service battery chargers are 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.

(continued)

BASES

BACKGROUND (continued)

When desired, the chargers 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.

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."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 6), and in the FSAR, Chapter 15 (Ref. 7), 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 unit. This includes maintaining the 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.

The DC sources satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

BASES (continued)

LCO

The DC electrical power sources, each source consisting of one battery, battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train 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 train DC electrical power source does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power source requires the battery and one charger per battery 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 the Bases for LCO 3.8.5, "DC Sources — Shutdown."

ACTIONS

A.1

Condition A represents one DC electrical source inoperable due to an inoperable battery A or B. This Condition contains a Completion Time that is risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer-based tool that may be used to aid in the risk assessment of online maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based

(continued)

BASES

ACTIONS

A.1 (continued)

on current plant configuration and equipment condition. Because battery A is necessary for emergency diesel generator (EDG) A to start and for generator field flashing, and similarly battery B for EDG B, Required Action A.1 is modified by a Note directing that the applicable Conditions and Required Actions of LCO 3.8.1 be entered for the EDG made inoperable by the inoperable battery. In addition, with either battery A or B inoperable, the associated DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in loss of DC to the associated 120 V vital AC bus. Recovery of the AC bus supporting the charger, especially if it is due to a loss of offsite power, will be hampered by the fact that many of the components necessary for the recovery (e.g., diesel generator control and field flash, AC load shed and diesel generator output circuit breakers, etc.) likely rely upon the battery. In addition, the energization transients of any DC loads that are beyond the capability of the battery charger and normally require the assistance of the battery will not be able to be brought online. The 24 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 10).

Compensatory measures are implemented to minimize the impact of the completion time for an inoperable battery. There should be no scheduled work or surveillance testing that could result in a reactor or turbine-generator trip hazard, cause a plant transient, or impact safety-related systems during the completion time for the LCO. This includes testing the solid-state protection system (SSPS) and the sequencer. Also, if the inoperable battery affects one of the Emergency Diesel Generators (EDG), the EDG would be declared inoperable, but would be available in the slow start mode. Finally, the completion time is not intended to provide for online preventive maintenance, but it is only to provide for more orderly corrective maintenance for a battery.

(continued)

BASES

ACTIONS
(continued)

B.1 and B.2

Condition B represents one DC electrical source inoperable due to an inoperable battery C or D. This Condition contains a Completion Time that is risk-informed. The Configuration Risk Management Program (CRMP) is used to assess changes in core damage frequency resulting from applicable plant configurations. The CRMP uses the equipment out of service risk monitor, a computer-based tool that may be used to aid in the risk assessment of online maintenance and to evaluate the change in risk from a component failure. The equipment out of service risk monitor uses the plant probabilistic risk assessment model to evaluate the risk of removing equipment from service based on current plant configuration and equipment condition. Neither batteries C nor D are necessary for the EDGs to start and for generator field flashing. However, they are required for breaker control power, instrumentation, RHR suction isolation valve inverters, etc. Therefore, it is prudent to verify the availability of the standby auxiliary transformer (SAT), and Required Action B.1 does that within 1 hour and once per 12 hours thereafter. With either battery C or D inoperable, the associated DC bus is being supplied by the OPERABLE battery charger. Any event that results in a loss of the AC bus supporting the battery charger will also result in loss of DC to the associated 120 V vital AC bus. Recovery of the AC bus supporting the charger, especially if it is due to a loss of offsite power, may be hampered by the fact that components necessary for the recovery likely rely upon the battery. The 24 hour limit allows sufficient time to effect restoration of an inoperable battery given that the majority of the conditions that lead to battery inoperability (e.g., loss of battery charger, battery cell voltage less than 2.07 V, etc.) are identified in Specifications 3.8.4, 3.8.5, and 3.8.6 together with additional specific completion times.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 10).

Compensatory measures are implemented to minimize the impact of the completion time for an inoperable battery. There should be no scheduled work or surveillance testing that could result in a reactor or turbine-generator trip hazard, cause a plant transient, or impact safety-related systems during the completion time for the LCO. This includes testing the solid-state protection system (SSPS) and the sequencer. Also, if the inoperable battery affects one of the Emergency Diesel Generators (EDG), the EDG would be declared inoperable, but would be available in the slow start mode. Finally, the completion time is not intended to provide for online preventive

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

maintenance, but it is only to provide for more orderly corrective maintenance for a battery.

C.1

Condition C represents one train with a loss of ability to completely respond to an event, and/or a potential loss of ability to remain energized during normal operation. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 10).

If one of the required DC electrical power sources is inoperable for reasons other than Condition A or B (e.g., inoperable battery charger or inoperable battery charger and associated inoperable battery), the remaining DC electrical power sources have 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 loss of the minimum necessary DC electrical sources 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. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power source and, if the DC electrical power source is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

D.1 and D.2

If the Required Actions of Condition A, B, or C cannot be met within the required Completion Times, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 9). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 9, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 DC electrical power sources inoperable, the Required Action is to restore at least one of the required inoperable DC electrical power sources to OPERABLE status within one hour to regain control power for the AC emergency power system. The one hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of at least one DC electrical power source. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref 10).

The Condition is modified by two Notes. The first Note states it is not applicable when the second DC electrical power source is intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one DC electrical power source is inoperable for any reason and a second DC electrical power source is found to be inoperable, or if two DC electrical power sources are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk

(continued)

BASES

ACTIONS

E.1 (continued)

Informed Completion Time for this LCO Condition can be no longer than 24 hours.

F.1 and F.2

If the Required Actions of Condition E cannot be completed within the required Completion Times, 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.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries 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 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 times the number of connected cells for the battery terminal voltage). 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 (Ref. 4). According to Regulatory Guide 1.32 (Ref. 5), the battery charger supply is recommended to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.2 (continued)

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 the necessary current for each system at the minimum established float voltage for 8 hours for systems A and B and 3 hours for systems C and D. 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.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest combined 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 systems A and B batteries are recharged when the measured charging current is ≤ 2 amps. The system C and D batteries are recharged when the measured charging current is ≤ 1 amp.

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

For a battery charger with charger output aligned to the associated 1E 125 VDC bus, this Surveillance 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.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

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.

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

REFERENCES

1. IEEE-308-1978.

2. 10 CFR 50, Appendix A, GDC 17.

3. IEEE-485-1983, June 1983.

4. FSAR, Chapter 8.

5. Regulatory Guide 1.32, February 1977.

6. FSAR, Chapter 6.

7. FSAR, Chapter 15.

8. Regulatory Guide 1.93, December 1974.

9. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

(continued)

BASES

REFERENCES (continued)

10. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

Table B 3.8.4-1
DC Sources

TYPE	VOLTAGE	TRAIN A	TRAIN B
DC sources	125 V	<u>System A</u> Battery 1/2AD1B One charger 1/2AD1CA or 1/2AD1CB *Bus powered by system A 1/2AD1	<u>System B</u> Battery 1/2BD1B One charger 1/2BD1CA or 1/2BD1CB *Bus powered by system B 1/2BD1
	125 V	<u>System C</u> Battery 1/2CD1B One charger 1/2CD1CA or 1/2CD1CB *Bus powered by system C 1/2CD1	<u>System D</u> Battery 1/2DD1B One charger 1/2DD1CA or 1/2DD1CB *Bus powered by system D 1/2DD1

* Operability requirements for the buses are addressed in Specifications 3.8.9, Distribution Systems — Operating, or 3.8.10, Distribution Systems — Shutdown.

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 FSAR, 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 subsystems 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.

The DC sources satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The DC electrical power sources required to support the necessary portions of AC, DC, and AC vital bus electrical

(continued)

BASES

LCO (continued)

power distribution subsystems required by LCO 3.8.10, "Distribution Systems — Shutdown," shall be OPERABLE. At a minimum, at least one train of DC electrical power sources with each DC source within the train (Systems A and C OR Systems B and D) consisting of one battery, and one required battery charger per battery, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE. The equipment associated with each train of DC Sources is shown in Table B 3.8.4-1.

In the case where the requirements of LCO 3.8.10 call for portions of a second train of the distribution subsystems to be OPERABLE (e.g., to support two trains of RHR, two trains of CREFS, or instrumentation such as High Flux at Shutdown Alarm (HFASA), containment ventilation isolation actuation, and/or CREFS actuation), the associated required DC bus(es) are OPERABLE if energized to the proper voltage from either:

- an OPERABLE DC Source, in accordance with LCO 3.8.5, or
- the associated charger(s) using the corresponding control equipment and interconnecting cabling within the train, in accordance with LCO 3.8.10.

(continued)

BASES

LCO (continued)

The above requirements ensure 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).

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6 provide assurance that:

a. Required features needed to mitigate a fuel handling accident are available;

b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. 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.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If two subsystems are required by LCO 3.8.10, the remaining subsystem with DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. 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, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

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 subsystems 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 subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance 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 the actual performance is not required.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, 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 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, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.19 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "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 121.8 V for a 59 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 2.23 Vpc corresponds to a total float voltage output of 131.6 V for a 59 cell battery as discussed in the FSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, 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.

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 unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Battery parameters satisfy 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 are conducted as specified in Specification 5.5.19.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power sources. 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.

ACTIONS

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

With one or more cells in one battery < 2.07 V, battery capacity may be reduced. 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 < 2.07 V, 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Condition B addresses the case where battery A or B has float current > 2 amps; or battery C or D has float current > 1 amp. This 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 V, 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 V 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.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V 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.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

C.1, C.2, and C.3

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 5.5.19, Battery Monitoring and Maintenance Program). 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 5.5.19.b item to initiate action to equalize and test in accordance with manufacturer's recommendation are taken from Annex D of IEEE Standard 450-1995. 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.

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.

(continued)

BASES

ACTIONS (continued)

E.1

With two or more 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 more than one battery is involved. With more than one battery involved, this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer completion times specified for battery parameters on a single battery not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least three batteries within 2 hours.

F.1

With one or more batteries with any battery parameter outside the allowances of the Required Actions for Condition A, B, C, D, or E, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC battery must be declared inoperable. Additionally, discovering a battery with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps for batteries A and B, or 1 amp for batteries C and D indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately. This condition is intended to apply when the battery is in the float mode. For example, if an individual cell is discovered below the 2.07 V limit, a possible corrective action would be to place the battery in the equalize mode. In this condition, the charger amperage is elevated and a measurement of ‘float’ current may be above the stated limits with an individual cell below the 2.07 V criteria. This is an expected condition; therefore, in this case, it is not appropriate to enter Condition F.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1 (continued)

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.1 are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limits of 2 amps for batteries A and B, and 1 amp for batteries C and D are established based on the nominal float voltage value and are 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 129.8 V 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, is addressed in Specification 5.5.19. 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 V. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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., 70 °F). Pilot

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.4 (continued)

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. 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 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.

The modified discharge test 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

recommend that the battery be replaced if its capacity is below 80% of the manufacturer 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 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 ratings, 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 reduced to only 24 months for batteries that retain capacity ≥ 100% of the manufacturer's ratings.

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 rating. These Frequencies are similar to those recommended by IEEE-450 (Ref. 1) and require that testing be performed in a conservative manner relative to the battery life and degradation which in turn will ensure that battery capacity is adequately monitored and that the battery remains capable of performing its intended function.

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.

Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1. Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2. Post Corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES (continued)

REFERENCES

1. IEEE-450-1995.
2. FSAR, Chapter 8.
3. FSAR, Chapter 6.
4. FSAR, Chapter 15.
5. IEEE-485-1983, June 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters — Operating

BASES

BACKGROUND

There are six Class 1E inverters that supply the six vital AC distribution panels that are specified in Table B 3.8.9-1. Each inverter is connected independently to one distribution panel. Each inverter/distribution panel is associated with one of four instrumentation and control power supply channels. Channels I and II have two inverters/distribution panels each; channels III and IV have only one inverter/distribution panel each. Channels I and III are associated with train A and channels II and IV are associated with train B. The six Class 1E inverters provide the preferred source of 120 V, 60 Hz power for the reactor protection system (RPS), the engineered safety feature actuation system (ESFAS), the nuclear steam supply system control and instrumentation, the post accident monitoring system, and the safety related radiation monitoring system. The power for the channel I, II, III, and IV inverters is from the Class 1E 125 VDC Train A, B, C, and D station batteries, respectively, or their associated chargers when the batteries are on float. The station batteries ensure continued operation of instrumentation systems in the event of a station blackout.

Each distribution panel may be connected to a backup source of Class 1E 120 VAC power in accordance with the ACTIONS provided for an inoperable inverter. The tie is through a local, manually operated breaker, which is mechanically interlocked with the breaker connecting the inverter to the distribution panel such that the distribution panel cannot be connected to both sources simultaneously. The backup 120 VAC power is derived from the train A and B vital 480 VAC distributing system via 480-120 V Class 1E regulating transformers that are qualified as isolation devices.

Since the inverters for each of the four channels are connected to independent battery systems, a loss of a single DC bus can only affect the DC power supply to one of the

(continued)

BASES

BACKGROUND (continued)

four channels. Each inverter is independently connected to its respective instrument distribution panel so that the loss of an inverter cannot affect more than one of the six distribution panels. Therefore no single failure in the instrumentation and control power supply system or its associated power supplies can cause a loss of power to more than one of the redundant loads.

Specific details on inverters and their operating characteristics are found in the FSAR, Chapter 8 (Ref. 1).

The inverters and associated channels, AC vital buses, and DC panels are shown below:

CHANNEL	INVERTER	AC VITAL BUS	DC PANEL
Channel I	1/2AD1I1	1/2AY1A	1/2AD1
Channel I	1/2AD1I11	1/2AY2A	1/2AD1
Channel II	1/2BD1I2	1/2BY1B	1/2BD1
Channel II	1/2BD1I12	1/2BY2B	1/2BD1
Channel III	1/2CD1I3	1/2CY1A	1/2CD1
Channel IV	1/2DD1I4	1/2DY1B	1/2DD1

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, 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 unit. This includes maintaining required AC vital buses OPERABLE during accident conditions in the event of:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power; 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).

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 six inverters ensure an uninterruptible supply of AC electrical power to the AC vital buses, as specified in Table B 3.8.9-1, even if the 4.16 kV safety buses are de-energized.

OPERABLE inverters require the associated vital bus to be powered by the inverter with output voltage and frequency within tolerances and power input to the inverter from a 125 VDC station battery.

This LCO is modified by a Note that allows two inverters to be disconnected from a common battery for ≤ 24 hours, if the vital bus is powered from a Class 1E regulating transformer during the period and all other inverters are operable. This allows an equalizing charge to be placed on one battery. These provisions minimize the loss of equipment that would occur in the event of a loss of offsite power. The 24 hour time period for the allowance minimizes the time during which a loss of offsite power could result in the loss of equipment energized from the affected AC vital bus while taking into consideration the time required to perform an equalizing charge on the battery bank.

The intent of this Note is to limit the number of inverters that may be disconnected. Only those inverters associated with the single battery undergoing an equalizing charge may

(continued)

BASES

LCO (continued)

be disconnected. All other inverters must be aligned to their associated batteries.

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 the Bases for LCO 3.8.8, "Inverters — Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is manually re-energized from its Class 1E regulating 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." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours 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 (Ref. 5). The 24 hour 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 vital bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible, battery backed inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices.

(continued)

BASES

ACTIONS

B.1 and B.2

If the Required Action of Condition A cannot be met within the required Completion Time, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action B.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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

With two or more inverters inoperable the Required Action is to restore at least one of the required inverters to OPERABLE status within one hour to regain AC electrical power to the vital buses. The one hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of at least one required inverter. Alternately, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 5).

(continued)

BASES

ACTIONS

C.1 (continued)

The Condition is modified by two Notes. The first Note states it is not applicable when two or more required inverters are intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one required inverter is inoperable for any reason and a second required inverter is found to be inoperable, or if two required inverters are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, “Risk Informed Completion Time Program”, which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours.

D.1 and D.2

If the Required Actions of Condition C cannot be completed within the required Completion Times, 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 a orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital 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 vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 8.

2. FSAR, Chapter 6.

3. FSAR, Chapter 15.

(continued)

BASES

REFERENCES (continued)

4. WCAP-16294-NP-A, Rev. 1, “Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs,” June 2010.

5. Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, “Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A (CAC Nos. ME9555 and ME9556).

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 FSAR, 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 minimum inverters to each AC vital 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.

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).

(continued)

BASES (continued)

LCO

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. Per LCO 3.8.10, "Distribution Systems — Shutdown," the necessary portions of the necessary AC vital bus electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE. At a minimum, at least one train of AC vital bus electrical power subsystems energized from the associated inverters connected to the respective DC bus is required to be OPERABLE.

In the case where the requirements of LCO 3.8.10 call for portions of a second train of the distribution subsystems to be OPERABLE (e.g., to support two trains of RHR, two trains of CREFS, or instrumentation such as High Flux at Shutdown Alarm (HFASA), containment ventilation isolation actuation, and/or CREFS actuation), the required AC vital bus electrical power distribution subsystems may be energized from the associated inverters with the inverters connected to the respective bus, in accordance with LCO 3.8.8, or the Class 1E regulated transformer, in accordance with LCO 3.8.10. 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 provide assurance that:

a. Systems needed to mitigate a fuel handling accident are available;

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. 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.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If two trains are required by LCO 3.8.10, "Distribution Systems — Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. 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'

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

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, and operations involving positive reactivity additions). 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 or powered from a regulating transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems — Operating

BASES

BACKGROUND

The onsite Class 1E AC electrical power distribution systems are divided by train into two redundant and independent AC electrical power distribution subsystems. The DC and AC vital buses are divided into four channels of distribution, two channels of which are associated with each train.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 4.16 kV bus and secondary 480 and 120 V buses, distribution panels, motor control centers, and load centers. 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 preferred offsite source. A transfer to the alternate offsite source can be made manually. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 4.16 kV ESF bus. Control power for the 4.16 kV breakers is supplied from the Class 1E batteries. 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 secondary AC electrical power distribution system for each train includes the safety related load centers, motor control centers, and distribution panels shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E regulating transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters — Operating." Each regulating transformer is powered from a Class 1E AC bus.

There are four independent 125 VDC electrical power distribution subsystems (two for each train).

The list of all required distribution buses is presented in Table B 3.8.9-1.

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BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1), and in the FSAR, Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC vital 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 vital 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 unit. 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; 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 listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital 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 vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the required AC, DC, and AC vital 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.

(continued)

BASES

LCO (continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels to be energized to their proper voltages. OPERABLE DC electrical subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage or Class 1E regulating transformer.

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable with the exceptions stated below. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.

The LCO is modified by a Note that allows an exception to the OPERABILITY requirement that all tie breakers must be open. This exception is provided for the sole purpose of facilitating the transfer of preferred offsite power sources independent of DG operation. The 4160 V ESF buses may be manually connected within the unit by tie breakers and fed from one offsite power source provided the following precautions and limitations are followed:

1. Either one of the RATs, but not the SAT, may be utilized as the single offsite power source for both 4160 V ESF buses during the transfer evolution;

2. No additional nonsafety related 4160 V loads, other than those normally fed from 4160 V ESF buses 1/2AA02 and 1/2BA03, shall be manually connected to the RAT while the buses are interconnected;

(continued)

BASES

LCO (continued)

3. The automatic bus transfer schemes for the nonsafety related 4160 V buses shall be disabled during the interconnection; and

4. The offsite power system shall have the minimum voltage necessary to assure that the offsite power source feeding both interconnected 4160 V safety buses has the capacity and capability to simultaneously sequence both trains of LOCA loads.

The closing of the tie breakers between the redundant 4160 V ESF buses is required in order to sustain a continuous source of power to the affected 4160 V ESF bus while the RAT is being disconnected. The LCO Note allows the SAT to be placed into service and the RAT to be removed from service during power operation with no degradation in the total number of preferred offsite or onsite emergency AC power sources required per GDC 17, i.e., both normal and alternate offsite and emergency standby power sources will be available. The Note also requires that SR 3.8.1.1 be performed within 12 hours of initiating the transfer of offsite circuits. Performance of SR 3.8.1.1 provides added assurance that all offsite circuits are OPERABLE prior to initiating the transfer. The applicable tie breaker(s) are allowed to be closed for the time required to complete the transfer of offsite circuits without declaring the affected buses inoperable.

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 the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

(continued)

BASES (continued)

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels, except AC vital buses, inoperable, and the remaining AC electrical power distribution subsystems 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 system reliability is reduced. A single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 5).

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. 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 train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

B.1

With one or more AC vital buses inoperable and the remaining OPERABLE AC vital buses 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. An additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter with DC power available to the inverter or the Class 1E regulating transformer. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref. 5).

(continued)

BASES

ACTIONS

B.1 (continued)

Condition B represents one or more AC vital buses 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 noninterruptable power.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC 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 vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential 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 vital buses to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

C.1

With one or more DC buses inoperable and the remaining DC electrical power distribution subsystems 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 system reliability is reduced. A single failure in the remaining DC electrical power distribution subsystem could result in

(continued)

BASES

ACTIONS

C.1 (continued)

the minimum required ESF functions not being supported. Therefore, the required DC buses 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 (Ref 5).

Condition C represents one or more DC subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all DC power.

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 train; and

c. The potential 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).

D.1 and D.2

If the Required Actions of Condition A, B, or C cannot be met within the required Completion Times, the unit must be brought to a MODE in which overall plant risk is reduced. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. Remaining within the Applicability of the LCO is acceptable to accomplish short duration repairs to restore inoperable equipment because the plant risk in MODE 4 is similar to or lower

(continued)

ACTIONS

D.1 and D.2 (continued)

than MODE 5 (Ref. 4). In MODE 4 the Steam Generators and Residual Heat Removal System are available to remove decay heat, which provides diversity and defense in depth. As stated in Reference 4, the steam turbine driven Auxiliary Feedwater Pump must be available to remain in MODE 4. Should Steam Generator cooling be lost while relying on this Required Action, there are preplanned actions to ensure long-term decay heat removal. Voluntary entry into MODE 5 may be made as it is also acceptable from a risk perspective.

Required Action D.2 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 4. This Note prohibits the use of LCO 3.0.4.a to enter MODE 4 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 4, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. 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 or more electrical power distribution subsystems inoperable that result in a loss of safety function, the Required Action is to restore sufficient electrical power distribution subsystems within one hour to restore safety function. The one hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of sufficient electrical power distribution subsystems. Alternately, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program (Ref 5).

The CONDITION is modified by two Notes. The first Note states it is not applicable when two or more electrical distribution subsystems are intentionally made inoperable. This Required Action is not intended for voluntary removal of redundant systems or components from service. The Required Action is only applicable if one electrical power distribution subsystem is inoperable for any reason and a second

(continued)

BASES

ACTIONS

E.1 (continued)

electrical power distribution subsystem is found to be inoperable, or if two electrical power distribution subsystems are found to be inoperable at the same time. The second Note indicates the parts of Section 5.5.22, "Risk Informed Completion Time Program", which are applicable to this LCO Condition. The Risk Informed Completion Time for this LCO Condition can be no longer than 24 hours.

F.1 and F.2

If the Required Actions of Condition E cannot be completed within the required Completion Times, 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.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with 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. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

4. WCAP-16294-NP-A, Rev. 1, "Risk-Informed Evaluation of Changes to Technical Specification Required Action Endstates for Westinghouse NSSS PWRs," June 2010.

(continued)

BASES

REFERENCES (continued)	5.	Vogtle Electric Generating Plant, Units 1 and 2 - Issuance of Amendments Regarding Implementation of Topical Report Nuclear Energy Institute NEI 06-09, "Risk-Informed Technical Specifications Initiative 4B, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A (CAC Nos. ME9555 and ME9556).

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN A*	TRAIN B*
AC safety buses	4160 V	Switchgear ESF Bus 1/2AA02	Switchgear ESF Bus 1/2BA03
	480 V	Switchgear 1/2AB04 1/2AB05 1/2AB15	Switchgear 1/2BB06 1/2BB07 1/2BB16
	480 V	Motor Control Centers 1/2ABE, 1/2ABA, 1/2ABC, 1/2ABF, 1/2ABB, 1/2ABD	Motor Control Centers 1/2BBE, 1/2BBA, 1/2BBC, 1/2BBF, 1/2BBB, 1/2BBD
DC buses***	125 V	Switchgear 1/2AD1 1/2CD1	Switchgear 1/2BD1 1/2DD1
	125 V	Distribution Panels 1/2AD11, 1/2AD12, 1/2CD11	Distribution Panels 1/2BD11, 1/2BD12, 1/2DD11
AC vital buses	120 V	Distribution Panels Channel I 1/2AY1A, 1/2AY2A Channel III 1/2CY1A Associated Regulating Transformers**	Distribution Panels Channel II 1/2BY1B, 1/2BY2B Channel IV 1/2DY1B Associated Regulating Transformers**

* Each train of the AC and DC electrical power distribution systems is a subsystem.
** A regulating transformer is a component of the Electrical Power Distribution Systems only when it is in service providing power to a 120 VAC vital bus.
*** Operability of 125 V Motor Control Centers 1/2AD1M and 1/2BD1M is addressed by LCOs 3.4.11, 3.4.12, and 3.7.5. Operability of Motor Control Center 1/2CD1M is addressed by LCO 3.7.5.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems — Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC vital 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 FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital 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 vital 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 vital bus electrical power distribution subsystems 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 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).

(continued)

BASES

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components — all specifically addressed in each LCO.

The necessary portions of the AC electrical power distribution subsystems are considered OPERABLE if they are energized to their proper voltages.

The necessary portions of the DC electrical power subsystems are considered OPERABLE if the following criteria are satisfied:

- At least one train of the necessary portions of DC electrical subsystems is energized to the proper voltage by an OPERABLE train of DC sources in accordance with LCO 3.8.5, "DC Sources," and

- In the case where portions of a second train of the DC electrical subsystems are required OPERABLE (to support two trains of RHR, two trains of CREFS, or instrumentation such as High Flux at Shutdown Alarm (HFASA), containment ventilation isolation actuation, and/or CREFS actuation), the required portions of DC electrical subsystems are OPERABLE when energized to the proper voltage from either:

    - an OPERABLE DC source in accordance with LCO 3.8.5, or

    - the associated charger using the corresponding control equipment and interconnecting cabling within the train. In some cases where there is an increased potential for the addition or removal of loads larger than breaker control power ("larger loads"), as provided in plant administrative controls, both the associated battery and associated charger are required to

(continued)

BASES

LCO (continued)

support the second train to ensure stability of the required 125 VDC bus. The addition or removal of larger loads on the DC bus or on a supported AC vital bus involves a higher potential of DC bus transients when there is only the charger tied to the bus.

The necessary portions of the AC vital bus subsystems are considered OPERABLE if the following criteria are satisfied:

- At least one train of the necessary portions of AC vital bus subsystems is energized to the proper voltage by OPERABLE inverters connected to the respective DC bus, in accordance with LCO 3.8.8, "Inverters — Shutdown," and

- In the case where portions of a second train of AC vital bus subsystems are required OPERABLE (to support two trains of RHR, two trains of CREFS, or instrumentation such as source range indication, containment ventilation isolation actuation, and/or CREFS actuation), the required portions of AC vital bus subsystems are OPERABLE when energized to the proper voltage from either:

    - an OPERABLE inverter in accordance with LCO 3.8.8, or

    - the associated Class 1E regulating transformer.

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 provide assurance that:

a. Systems needed to mitigate a fuel handling accident are available;

(continued)

BASES

APPLICABILITY (continued)

b. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

c. 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 vital bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

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, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's 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, 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.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.5 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR 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 vital bus electrical power distribution subsystems are functioning properly, with all the buses energized. The verification of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1 (continued)

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. FSAR, Chapter 6.
2. FSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the filled portions of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access 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 specified in the COLR ensures that an overall core reactivity of $k_{eff} \leq 0.95$ is maintained during fuel handling, with control rods and fuel assemblies in the most adverse configuration (least negative reactivity) consistent with the assumptions of the applicable safety analysis.

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.

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. The refueling canal and the refueling cavity are then flooded with borated water.

The pumping action of the Residual Heat Removal (RHR) System into the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. 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,

(continued)

BASES

BACKGROUND (continued)	"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 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 $\leq$ 0.95 during the refueling operation. During refueling, the water volume in the spent fuel pool, the transfer canal, 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. Since the Unborated Water Source Isolation Valves LCO, 3.9.2, requires the valve(s) used to isolate the unborated water sources to be secured in the closed position in MODE 6, the boron dilution events analyzed in this MODE are limited to a very small amount of unborated chemical solution that is allowed to enter the RCS for water chemistry quality control. The dilution flow path is provided by the allowance to open (under administrative control) valves in the flow path from the RMWST, through the chemical mixing tank, to the suction of the charging pumps. At all other times during MODE 6, at least one valve in each flow path from the RMWST to the suction of each charging pump will be secured closed and any other chemical makeup solution which is required during refueling will be borated water supplied from the refueling water storage tank by the RHR pumps. A more detailed discussion of the boron dilution event analyzed in this MODE is provided in the Bases for LCO 3.9.2.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
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 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} ≤ 0.95. In MODES 1 and 2, 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 shut down the reactor. In MODES 3, 4, and 5, LCO 3.1.1, "SHUTDOWN MARGIN" ensures an adequate amount of negative reactivity is available to shut down the reactor. The Applicability is modified by a Note. The Note states that the limits on boron concentration are only applicable to the refueling canal and the refueling cavity when those volumes are connected to the Reactor Coolant System. When the refueling canal and the refueling cavity are isolated from the RCS, no potential path for boron dilution exists.
ACTIONS	<u>A.1 and A.2</u> 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. 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, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the 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.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in all filled portions of the RCS, and connected portions of the refueling canal and the refueling cavity, is within the COLR limits. The boron concentration of the coolant in each required volume is determined periodically by chemical analysis. Prior to re-connecting portions of the refueling canal or the refueling cavity to the RCS, this SR must be met per SR 3.0.4. If any dilution has occurred while the cavity or canal were disconnected from the RCS, this SR ensures the correct boron concentration prior to communication with the RCS.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. FSAR, Subsection 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Isolation Valves

BASES

BACKGROUND

During MODE 6 operations, all flow paths from reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be isolated to prevent unplanned boron dilution of the reactor coolant. The appropriate isolation valve(s) 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.

At least one valve in each flow path from the Reactor Makeup Water Storage Tank (RMWST) to the suction of each charging pump shall be closed and secured in position except as provided for in the Note to the LCO. The applicable valve(s) will be controlled by plant procedures, which will ensure proper valve position.

APPLICABLE SAFETY ANALYSES

The possibility of an inadvertent 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.

However, since this LCO is modified by a Note that allows a very small amount of unborated chemical solution to enter the RCS for the purpose of water chemistry quality control, a boron dilution event is analyzed in this MODE. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

dilution flow path from the RMWST, through the chemical mixing tank, to the suction of the charging pumps, is provided by the allowance to open (under administrative control) applicable Chemical and Volume Control System (CVCS) valves. The maximum flow rate possible through this flow path is less than 3.5 gal/min which is approximately 3.0 percent of the limiting flow rate considered in the analysis for other MODES. At all other times during MODE 6, the valve(s) are secured closed and any other chemical makeup solution which is required during refueling will be borated water supplied from the refueling water storage tank by the RHR pumps. Flow paths from the CVCS which could allow unborated chemical makeup water in excess of 3.5 gal/min to reach the RCS are always isolated in MODE 6 by maintaining at least one valve secured closed in each applicable flow path. Since the maximum flow rate associated with the available dilution flow paths in MODE 6 is very small, the total time from initiation of event to the eventual complete loss of shutdown margin is significantly large compared to the minimum required operator action time. Therefore, a considerable amount of time is available for the operator to initiate and terminate procedures for RCS water chemistry adjustments before potential loss of shutdown becomes a concern. Additionally, the high flux at shutdown (HFAS) alarm is required OPERABLE prior to the applicable CVCS valves being opened. The boron dilution event analysis specifically credits the HFAS alarm when these valves are open. The availability of the HFAS alarm ensures that the operator has a 30 minute warning to terminate the dilution before shutdown margin is lost.

The RCS boron concentration satisfies 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. This is accomplished by maintaining at least one valve secured closed in each applicable flow path.

The LCO is modified by a Note that allows valves in the flow path from the RMWST, through the chemical mixing tank, to the suction of the charging pumps to be opened under

(continued)

BASES

LCO (continued)

administrative control provided the reactor coolant system boron concentration is within the limit specified in the COLR and the high flux at shutdown alarm is OPERABLE. The high flux at shutdown alarm is not normally required OPERABLE in MODE 6, however for the purpose of meeting the requirement stated in this Note, the high flux at shutdown alarm is considered OPERABLE if the applicable surveillance requirements of LCO 3.3.8, High Flux at Shutdown Alarm and LCO 3.9.3, Nuclear Instrumentation are met.

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.

ACTIONS

The ACTIONS do not apply to valves in the flow path from the RMWST, through the chemical mixing tank, to the suction of the charging pumps, when opened under administrative control in accordance with the Note in the LCO. The ACTIONS table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1

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.

Condition A has been modified by a Note to require that Required Action A.3 be completed whenever Condition A is entered.

(continued)

BASES

ACTIONS (continued)

A.2

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valve(s) secured closed. Securing the valve(s) in the closed position ensures that the valve(s) 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 immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

A.3

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 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valve(s) 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 every 72 hours during MODE 6 under SR 3.9.1.1. This Surveillance demonstrates that the valves are closed through a system walkdown. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. FSAR, Subsection 15.4.6.

2. NUREG-0800, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors (NI-0031 and NI-0032) are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. Temporary neutron flux detectors which provide equivalent indication may be utilized in place of installed instrumentation.

The installed source range neutron flux monitors are fission chamber detectors. The detectors monitor the neutron flux in counts per second. The instrument range covers seven decades of neutron flux (1E-1 cps to 1E +6 cps) with a 2% instrument accuracy. The detectors also provide continuous visual indication in the control room. The NIS is designed in accordance with the criteria presented in Reference 1.

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 an improperly loaded fuel assembly. The need for a safety analysis for an uncontrolled boron dilution accident is minimized by isolating all unborated water sources except as provided for by LCO 3.9.2, "Unborated Water Source Isolation Valves."

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

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. To be OPERABLE each monitor must provide visual indication.

When any of the safety-related busses supplying power to one of the detectors (NI-0031 or NI-0032) associated with the source range neutron flux monitors are taken out of service, the corresponding source range neutron flux monitor may be considered OPERABLE when its detector is powered from a temporary nonsafety-related

(continued)

BASES

LCO (continued)	source of power, provided the detector for the opposite source range neutron flux monitor is powered from its normal source.
APPLICABILITY	In MODE 6, the 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 MODES 2, 3, 4, and 5, the operability requirements for the installed source range detectors and circuitry are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

ACTIONS

A.1 and A.2

With only one 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 shall not preclude completion of movement of a component to a safe position or normal cooldown of the coolant volume for the purpose of system temperature control.

B.1

Condition B is modified by a Note to clarify the requirement that entry into or continued operation in accordance with Condition A is required for any entry into Condition B. The Note reinforces conventions of LCO applicability as stated in LCO 3.0.2 and as reflected in examples in 1.3, Completion Times.

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, actions shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be

(continued)

BASES

ACTIONS

B.2 (continued)

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 to ensure that unplanned changes in boron concentration would be identified. The 12 hour Completion Time is reasonable, considering the low probability of a change in core reactivity during this time period.

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 includes obtaining the detector preamp discriminator curves and evaluating those curves. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of 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 MODE 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 closed or capable of being closed. Since there is no 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 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

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. If closed, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced. Alternatively, the equipment hatch can be open provided it can be installed with a minimum of four bolts holding it in place.

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." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is

(continued)

BASES

BACKGROUND (continued)

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 CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the door interlock mechanism may remain disabled, but one air lock door must always must be isolable by at least one air lock door with a designated individual available to close the air lock door, or at least one air lock door must be closed.

The emergency air lock will not normally be open during core alterations or fuel movement inside containment. Therefore, in the event the emergency air lock is open at the same time the personnel air lock is open, a separate individual shall be responsible for closing the emergency air lock (within 15 minutes) in addition to the individual designated to close the personnel air lock.

The requirements for containment penetration closure are sufficient to ensure fission product radiactivity release from containment due to a fuel handling accident during refueling is maintained to within the acceptance criteria of Standard Review Plan Section 15.7.4 and General Design Criteria 19.

The Containment Ventilation System consists of two 24 inch penetrations for purge and exhaust of the containment atmosphere. Each main or shutdown purge and exhaust system contains one motor operated 24 inch valve inside containment and one motor operated 24 inch valve outside containment (HV-2626A, HV-2627A, HV-2628A, and HV-2629A). A second 14 inch mini-purge and exhaust system shares each 24 inch penetration and consists of one 14 inch pneumatically operated valve inside containment and one outside of containment (HV-2626B, HV-2627B, HV-2628B, and HV-2629B). A 14 inch mini-purge line is connected to each 24 inch line between the 24 inch isolation valve and the penetration both inside and outside containment.

In MODES 1, 2, 3 and 4 the 24 inch main or shutdown purge and exhaust valves are secured in the closed position. The 14 inch mini-purge and exhaust valves may be opened in these MODES in accordance with LCO 3.6.3, Containment Isolation Valves, and are automatically closed by a Containment Ventilation Isolation signal. The instrumentation that provides the automatic isolation function for these valves is listed in LCO 3.3.6, Containment Ventilation Isolation Instrumentation.

(continued)

BASES

BACKGROUND (continued)

In MODE 6, the 24 inch main or shutdown purge and exhaust valves are used to exchange large volumes of containment air to support refueling operations or other maintenance activities. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment any open 24 inch valves are capable of being closed (LCO 3.3.6). The 14 inch mini-purge and exhaust valves, though typically not opened during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, if opened are also capable of being closed (LCO 3.3.6).

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 for the other containment penetrations during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment (Ref. 1).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of 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. 2). Fuel handling accidents, analyzed in Reference 2, include dropping a single irradiated fuel assembly onto another irradiated fuel assembly.

To support the plant configuration of both air lock doors open (personnel and/or emergency air locks), and to further minimize an unmonitored, untreated release, the designated individual for closure of the air lock will have the air lock closed within 15 minutes of the fuel handling accident. The 15 minute duration was chosen as the limit for the response capability for the person who is designated for closing the air lock door. The NRC

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

acceptance of this specification was based on doses for a 2 hour release as well as a licensee commitment for a person designated to close the door quickly.

The requirements of LCO 3.9.7, "Refueling Cavity Water Level," and the minimum decay time of 90 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 100 values as specified in Regulatory Guide 1.195 (Ref. 3). The radiological consequences of a fuel handling accident in containment have been evaluated assuming that the containment is open to the outside atmosphere. All airborne activity reaching the containment atmosphere is assumed to be exhausted to the environment within 2 hours of the accident. The calculated offsite and control room operator doses are within the acceptance criteria of Regulatory Guide 1.195 and GDC 19. Therefore, although the containment penetrations do not satisfy any of the 10 CFR 50.36 (c)(2)(ii) criteria, LCO 3.9.4 provides containment closure capability to minimize potential offsite doses.

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires the equipment hatch, the air locks, and any penetration providing direct access to the outside atmosphere to be closed or capable of being closed. Personnel air lock closure capability is provided by the availability of at least one door and a designated individual to close it. Emergency air lock closure capability is provided by the availability of at least one door and a designated individual to close it. Equipment hatch closure capability is provided by a designated trained hatch closure crew and the necessary equipment. For the OPERABLE containment ventilation penetrations, this LCO ensures that each penetration is isolable by the Containment Ventilation Isolation valves. The OPERABILITY requirements for LCO 3.3.6, Containment Ventilation Isolation Instrumentation ensure that radiation monitor inputs to the control room alarm exist so that operators can take timely

(continued)

BASES

LCO (continued)

action to close containment penetrations to minimize potential offsite doses. The LCO requirements for penetration closure may also be met by the automatic isolation capability of the CVI system. Temporary non-1E power may be supplied to the air operated and/or solenoid operated CVI valves. The temporary non-1E power must be connected in such a way that it cannot affect the capability of the valves to close either automatically or manually from the control room handswitch.

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident.

Item b of this LCO includes requirements for both the emergency air lock and the personnel air lock. The personnel and emergency air locks are required by Item b of this LCO to be isolable by at least one air lock door in each air lock. Both containment personnel and emergency air lock doors may be open during movement of irradiated fuel in the containment and during CORE ALTERATIONS provided at least one air lock door is isolable in each air lock. An air lock is isolable when the following criteria are satisfied:

1. one air lock door is OPERABLE,

2. at least 23 feet of water shall be maintained over the top of the reactor vessel flange in accordance with Specification 3.9.7,

3. a designated individual is available to close the door.

OPERABILITY of a containment air lock door requires that the door seal protectors are easily removed, that no cables or hoses are being run through the air lock, and that the air lock door is capable of being quickly closed.

The equipment hatch is considered isolable when the following criteria are satisfied:

1. the necessary equipment required to close the hatch is available.

(continued)

BASES

LCO (continued)

2. at least 23 feet of water is maintained over the top of the reactor vessel flange in accordance with Specification 3.9.7,

3. a designated trained hatch closure crew is available.

Similar to the air locks, the equipment hatch opening must be capable of being cleared of any obstruction so that closure can be achieved as soon as possible.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1, "Containment." In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, 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 the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of 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 in its closed position is in that position. The Surveillance on the required open containment ventilation isolation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each required valve operator has motive power, which will ensure that each valve is capable of being closed.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.4.2

This Surveillance demonstrates that each containment ventilation isolation valve in each open containment ventilation penetration actuates to its isolation position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note stating that this surveillance is not required to be met for valves in isolated penetrations. LCO 3.9.4.c.1 provides the option to close penetrations in lieu of requiring automatic actuation capability.

SR 3.9.4.3

The equipment hatch is provided with a set of hardware, tools, and equipment for moving the hatch from its storage location and installing it in the opening. The required set of hardware, tools, and equipment shall be inspected to ensure that they can perform the required functions.

The 7 day frequency is adequate considering that the hardware, tools, and equipment are dedicated to the equipment hatch and not used for any other functions.

The SR is modified by a Note which only requires that the surveillance be met for an open equipment hatch. If the equipment hatch is installed in its opening, the availability of the means to install the hatch is not required.

REFERENCES

1. GPU Nuclear Safety Evaluation SE-0002000-001, Rev. 0, May 20, 1988.

2. FSAR, Subsection 15.7.4.

3. Regulatory Guide 1.195, May 2003.

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. 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 the bypass line(s). Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.
APPLICABLE SAFETY ANALYSES	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 refueling cavity water level. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RHR and Coolant Circulation - High Water Level satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

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. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation 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 and to determine the low end temperature. 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.

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

(continued)

BASES

APPLICABILITY (continued)

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 other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). 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

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS because all of unborated water sources are isolated.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. 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.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling

(continued)

BASES

ACTIONS

A.3 (continued)

water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. 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 (FIC-0618A and FIC-0619A) 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.2 (continued)

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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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. Operating procedures direct the implementing actions to meet this SR and ensure the system is sufficiently filled with water.

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 RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.2 (continued)

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lines. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

NONE

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. 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 the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

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 refueling cavity water level. 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).

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE.

(continued)

BASES

LCO (continued)

Additionally, one loop of RHR 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.

This LCO is modified by two Notes. The first Note allows one RHR loop to be inoperable for a period of 2 hours provided the other loop is OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include that the core time to boil is short, there is no draining operation to further reduce RCS water level and that the capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

The second Note permits the RHR pumps to be de-energized for </= 15 minutes when switching from one train to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is limited to > 10 degrees F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

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 other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). 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."

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation 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

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS, because all of the unborated water sources are isolated.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. 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.

(continued)

BASES (continued)

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. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.6.2

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 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 the accumulated gas is eliminated or brought within the acceptance criteria limits during performance of the Surveillance, the Surveillance is met and past system OPERABILITY is evaluated under the Corrective Action Program. 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. Operating

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.6.2 (continued)

procedures direct the implementing actions to meet this surveillance requirement and ensure the system is sufficiently filled with water. 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 RHR system is assumed to remain sufficiently filled with water and may be restarted following short term duration RHR shutdowns, if no evolutions were performed that can introduce voids into the RHR loop.

This SR is modified by a Note clarifying that the SR may be met for a running RHR Loop by virtue of having the RHR Loop in service in accordance with operating procedures except when the RHR Loop is in a low flow system operation which could allow the potential of gas voids not transporting through the system and the potential accumulation of gas voids in stagnant branch lies. RHR Loop low flow operation for gas accumulation is when the RHR system flow is below the system minimum flow valve closing setpoint (allowing the miniflow valve to be open).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

NONE

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies or performance of CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.195 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water.

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 90 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 3 and 4).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii).
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, as provided by the guidance of Reference 3.
APPLICABILITY	LCO 3.9.7 is applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, and when moving irradiated fuel assemblies within containment. Unlatching and latching of control rod drive shafts includes drag testing of the associated rod cluster control assembly. The LCO ensures a sufficient level of water is present in the reactor 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 3.7.15, "Fuel Storage Pool Water Level."
ACTIONS	<u>A.1 and A.2</u> With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

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 1.195, May 2003.

2. FSAR, Subsection 15.7.4.

3. 10 CFR 100.11

4. Malinowski, D. D., Bell, M. J., Duhn, E., and Locante, J., WCAP-7828, Radiological Consequences of a Fuel Handling Accident, December 1971.