Enclosure C
L-23-052

PNPP Technical Specification Bases, Revision 18

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PERRY NUCLEAR POWER PLANT

TECHNICAL SPECIFICATIONS BASES

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PERRY NUCLEAR POWER PLANT
Technical Specifications Bases (TSB)
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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC (Ref. 1) requires, and SLs ensure, that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measureable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. This is accomplished by having a Safety Limit Minimum Critical Power Ratio (SLMCPR) design basis, referred to as $SLMCPR_{95/95}$, which corresponds to a 95% probability at a 95% confidence level (the 95/95 MCPR criterion) that transition boiling will not occur.

(continued)

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling 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.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The Tech Spec SL is set generically on a fuel product MCPR correlation basis as the MCPR which corresponds to a 95% probability at a 95% confidence level that transition boiling will not occur, referred to as $SLMCPR_{95/95}$.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR SL.

2.1.1.1 Fuel Cladding Integrity

GE critical power correlations are applicable for all critical power calculations at pressures ≥ 686 psig and core flows ≥ 10% of rated flow. For operation at low pressures or low flows, another basis is used, as follows:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be > 4.5 psi. Analyses (Ref. 2) show that with a bundle flow of 28 x 10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

indicate that the fuel assembly critical power at this flow is approximately 3.35 Mwt. With the design peaking factors, this corresponds to a THERMAL POWER > 47.6% RTP. Thus, a THERMAL POWER limit of 23.8% RTP for reactor pressure < 686 psig is conservative.

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. The Technical Specification SL value is dependent on the fuel product line and the corresponding MCPR correlation, which is cycle independent. The value is based on the Critical Power Ratio (CPR) data statistics and a 95% probability with 95% confidence that rods are not susceptible to boiling transition, referred to as $MCPR_{95/95}$.

The SL is based on GNF2 fuel. For cores with a single fuel product line, the $SLMCPR_{95/95}$ is the $MCPR_{95/95}$ for the fuel type. For cores loaded with a mix of applicable fuel types, the $SLMCPR_{95/95}$ is based on the largest (i.e., most limiting) of the MCPR values for the fuel product lines that are fresh or once-burnt at the start of the cycle.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	<u>2.1.1.3 Reactor Vessel Water Level</u> During MODES 1 and 2, the reactor vessel water level is required to be above the top of the active fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level becomes less than two thirds of the core height. The reactor vessel water level SL has been established at the top of the active irradiated fuel to provide a point that can be monitored and also to provide adequate margin for effective action.
SAFETY LIMITS	The reactor core SLs are established to protect the integrity of the fuel clad barrier to the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel, in order to prevent elevated clad temperatures and resultant clad perforation.
APPLICABILITY	SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.
SAFETY LIMIT VIOLATIONS	<u>2.2</u> Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident Source Term," limits (Ref. 3). Therefore, it is required to insert all insertable control rods and restore compliance

(continued)

BASES

SAFETY LIMIT VIOLATIONS

2.2 (continued)

with the SL within 2 hours. These actions will include restoring reactor vessel water level in accordance with the Emergency Operating Procedures (e.g., manually initiating the ECCS or depressurizing the reactor vessel). The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

Per 10 CFR 50.36(c)(1)(i)(A), operation must not be resumed until authorized by the Nuclear Regulatory Commission.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 10.
2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR-II" (latest approved revision).
3. 10 CFR 50.67.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on reactor steam dome pressure protects 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. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. 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) shall be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation and anticipated operational occurrences (AOOs).

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, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation." 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 reducing the number of protective barriers originally designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4), now 10 CFR 50.67 (Ref. 10). If this occurred in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.

APPLICABLE SAFETY ANALYSES

The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure-High Function have settings established to ensure that the RCS pressure SL will not be exceeded.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition, including Addenda through the Winter of 1972 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. A weld overlay repair was performed on a feedwater nozzle to safe-end weld (1B13-N4C-KB), using a different Code Edition (Ref. 9), which did not affect this maximum transient pressure limit. The SL of 1325 psig, as measured in the reactor steam dome, is equivalent to 1375 psig at the lowest elevation of the RCS. The RCS is currently designed to ASME Code, Section III, 1983 Edition, including addenda through the Winter of 1984 (Ref. 6), for the reactor recirculation piping, which permits a maximum pressure transient of 110% of design pressures of 1250 psig for suction piping, 1650 psig for discharge piping between the pump and the discharge valve, and 1550 psig beyond the discharge valve. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.
SAFETY LIMITS	The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 110% of design pressures of 1250 psig for suction piping, 1650 psig for discharge piping between the pump and the discharge valve, and 1550 psig beyond the discharge valve. The most limiting of these allowances is the 110% of the suction piping design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1325 psig as measured in the reactor steam dome.
APPLICABILITY	SL 2.1.2 applies in all MODES.

(continued)

BASES (continued)

SAFETY LIMIT VIOLATIONS

2.2

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident Source Term," limits (Ref. 10). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. These actions will include restoring reactor vessel water level in accordance with the Emergency Operating Procedures (e.g., manually initiating the ECCS or depressurizing the reactor vessel). The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 14, and GDC 15.
2. ASME, Boiler and Pressure Vessel Code, Section III.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWA-5000.
4. 10 CFR 100.
5. ASME, Boiler and Pressure Vessel Code, 1971 Edition, Addenda, Winter of 1972.
6. ASME, Boiler and Pressure Vessel Code, 1983 Edition, Addenda, Winter of 1984.
7. Deleted
8. Deleted
9. USAR Table 3.2-7.
10. 10 CFR 50.67

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 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 ACTIONS.) The second type of Required Action specifies the

(continued)

BASES

LCO 3.0.2 (continued)

remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

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

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.11, "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.

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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.

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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 4 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 4, or other applicable MODE, is not reduced. For example, if MODE 2 is entered in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for entering MODE 3 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, and 3, 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 4 and 5 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, or 3) 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 3.7.7, “Fuel Pool Water Level.” LCO 3.7.7 has an Applicability of “During movement of irradiated fuel

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BASES

LCO 3.0.3 (continued)

assemblies in the associated fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.7 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 3.7.7 of "Suspend movement of irradiated fuel assemblies in the associated fuel storage pool(s)" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

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

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

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified 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 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

This 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 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

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

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

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the

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BASES

LCO 3.0.4 (continued)

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

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., 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. Startup with inoperable equipment should be the exception rather than the rule. The LCO 3.0.4.b allowance should be used only when it has been determined that there is a high likelihood that the LCO will be satisfied within the Required Action's Completion Time, after the Mode change.

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

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LCO 3.0.4 (continued)

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 or 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

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

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

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

b. The OPERABILITY of other equipment.

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BASES

LCO 3.0.5 (continued)

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 Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel. 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 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 support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system's LCO be entered solely due to the inoperability of the support

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BASES

LCO 3.0.6 (continued)

system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified in the support systems' 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' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant 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.

Specification 5.5.10, “Safety Function Determination Program” (SFDP), ensures loss of safety function is detected and appropriate actions are taken. Upon failure to meet two or more LCOs concurrently, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

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

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BASES

LCO 3.0.6 (continued)

LCO 3.0.6 addresses support systems that have an LCO specified in the TS. For support systems that do not have an LCO specified in the TS, the following guidance applies.

In most cases, the non-TS support system has two subsystems, each supporting just one TS division of safety equipment. The duration of a maintenance activity on such a non-TS support system is limited by the Required Action Completion Times of the supported TS system(s). In this case, because the outage time of the non-TS support system is limited by the supported system TSs, the plant is temporarily allowed to depart from the single-failure design criterion, but the licensee may not rely solely on the TS limitations. The licensee must still assess and manage risk in accordance with 10 CFR 50.65(a)(4).

In some cases, the non-TS support system has two redundant 100 percent capacity subsystems, each capable of supporting both TS divisions, e.g., M23/24, M28, M32, and P47. Loss of one support subsystem does not result in a loss of support for either division of TS equipment. Both TS divisions remain operable, despite a loss of support function redundancy, because the TS definition of operability does not require a TS subsystem’s necessary support function to meet the single-failure design criterion. Thus, no TS limits the duration of the non-TS support subsystem outage, even though the single-failure design requirement of the supported TS systems is not met. However, by assessing and managing risk in accordance with 10 CFR 50.65(a)(4), the licensee can determine an appropriate duration for the maintenance activity. Use of administrative controls to implement such a risk-informed limitation is an acceptable basis for also allowing a temporary departure from the design-basis configuration during such maintenance. Although not expected, were a licensee to determine that its risk assessment would permit the support subsystem to be inoperable for more than 90 days, then the licensee would have to evaluate the maintenance configuration as a change to the facility under 10 CFR 50.59, including consideration of the single-failure design criterion.

For the unusual non-TS support system design configuration described, the preceding is a clarification of the previous staff position (GL 80-30) regarding when a temporary departure from the single-failure design criterion is allowed. This allowance would be permitted regardless of whether the maintenance is corrective or preventive.

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LCO 3.0.6 (continued)	When a non-TS support subsystem is unexpectedly found to be in a degraded or non-conforming condition, the licensee must make a prompt determination of operability (functionality), as discussed in Generic Letter 91-18. If the non-TS support subsystem is determined to be inoperable (non-functional), then the licensee must determine whether the subsystem's support function is actually needed to support OPERABILITY of the TS supported systems. If the support function is required, then the risk-management strategies of the TS and 10 CFR 50.65(a)(4), as described above for planned maintenance, will determine the appropriate actions and time limits to return the non-TS subsystem to operable (functional) status. If the non-TS support function cannot be maintained, then enter the LCO(s) of the TS supported system(s).
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. Special Operations LCOs in Section 3.10

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BASES

LCO 3.0.7 (continued)

allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO's ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

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 TS

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BASES

LCO 3.0.8 (continued)

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 supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8 is an allowance, not a requirement. When one or more snubbers are unable to perform their associated support function(s), the supported system may be immediately declared inoperable instead of using LCO 3.0.8.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single division or subsystem of a multiple division or subsystem supported system or to a single division 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 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 and due to the availability of the redundant division 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 division or subsystem of a multiple division 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. For example, if more than one ECCS subsystem is affected, LCO 3.0.8.b is applicable.

Every time the provisions of LCO 3.0.8 are used it must be confirmed that at least one division (or subsystem) of systems supported by the inoperable snubber(s) would remain capable of performing their required safety or supported functions for postulated non-seismic design loads.

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BASES

LCO 3.0.8 (continued)

Every time the provisions of LCO 3.0.8 are used, it must be verified that at least one success path, involving equipment not associated with the inoperable snubber(s), exists to provide makeup and core cooling needed to mitigate LOOP accident sequences. To ensure this requirement is met, one of the following two means of heat removal must be available when LCO 3.0.8 is used:

a. At least one high-pressure makeup path (high pressure core spray or reactor core isolation cooling) and heat removal capability (e.g. suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s), or

b. At least one low pressure makeup path (low pressure coolant injection or core spray) and heat removal capability (e.g. suppression pool cooling or shutdown cooling), including a minimum set of supporting equipment required for success, not associated with the inoperable snubber(s).

LCO 3.0.8 only applies to the seismic function of a snubber. In addition, a record of the design function of the inoperable snubber (i.e., seismic versus non-seismic), the implementation of the applicable restrictions, and the associated plant configuration shall all be available on a recoverable basis.

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 must 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 division 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.

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 to be not 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 Special Operations LCO are only applicable when the Special Operations LCO 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.

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BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed. Some examples of this process are:

a. Control rod drive maintenance during refueling that requires scram testing at ≥ 950 psig. However, if other appropriate testing is satisfactorily completed and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psig to perform other necessary testing.

b. Reactor core isolation cooling (RCIC) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with RCIC considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

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).

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BASES

SR 3.0.2 (continued)

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 Primary 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 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

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BASES

SR 3.0.3 (continued)

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 performed 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 inadvertently missed. This delay period permits the performance of a Surveillance before complying with Required Actions or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 also 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

(continued)

BASES

SR 3.0.3 (continued)

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 inadvertently 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.

The risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed

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BASES

SR 3.0.3 (continued)

Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide and in the standard which it endorses, NUMARC 93-01, Revision 3, 'Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.' 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 Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then 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.

SR 3.0.4 contains two exceptions which explain its interrelationship with SR 3.0.3 and LCO 3.0.4. The first exception is in the first sentence, and clarifies that 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. A provision is also included in the second sentence of SR 3.0.4 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

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BASES

SR 3.0.4 (continued)

with LCO 3.0.4. In certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment or variables outside specified limits. When equipment is inoperable, or variables are outside their specified limits, 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, on equipment that is inoperable, or on variables that are outside specified limits, does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions in 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.

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 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 SR 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 or 3, MODE 2 to MODE 3, and MODE 3 to MODE 4.

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BASES

SR 3.0.4 (continued)

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

SDM requirements are specified to ensure:

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

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits; and

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

These requirements are satisfied by the control rods, as described in GDC 26 (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE SAFETY ANALYSES

The control rod drop accident (CRDA) analysis (Refs. 2 and 3) assumes the core is subcritical with the highest worth control rod withdrawn. Typically, the first control rod withdrawn has a very high reactivity worth and, should the core be critical during the withdrawal of the first control rod, the consequences of a CRDA could exceed the fuel damage limits for a CRDA (see Bases for LCO 3.1.6, "Control Rod Pattern"). Also, SDM is assumed as an initial condition for the control rod removal error during a refueling accident (Ref. 4). The analysis of this reactivity insertion event assumes the refueling interlocks are OPERABLE when the reactor is in the refueling mode of operation. These interlocks prevent the withdrawal of more than one control rod from the core during refueling. (Special consideration and requirements for multiple control rod withdrawal during refueling are covered in Special Operations LCO 3.10.6, "Multiple Control Rod Withdrawal – Refueling"). The analysis assumes this condition is acceptable since the core will be shut down with the highest worth control rod withdrawn, if adequate SDM has been demonstrated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Prevention or mitigation of reactivity insertion events is necessary to limit energy deposition in the fuel to prevent significant fuel damage, which could result in undue release of radioactivity. Adequate SDM provides assurance that inadvertent criticalities and potential CRDAs involving high worth control rods (namely the first control rod withdrawn) will not cause significant fuel damage. SDM satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The specified SDM limit accounts for the uncertainty in the demonstration of SDM by testing. Separate SDM limits are provided for testing where the highest worth control rod is determined analytically or by measurement. This is due to the reduced uncertainty in the SDM test when the highest worth control rod is determined by measurement. When SDM is demonstrated by calculations not associated with a test to determine the highest worth control rod, additional margin is included to account for uncertainties in the calculation. To ensure adequate SDM during the design process, a design margin is included to account for uncertainties in the design calculations (Ref. 5).
APPLICABILITY	In MODES 1 and 2, SDM must be provided because subcriticality with the highest worth control rod withdrawn is assumed in the CRDA analysis (Ref. 3). In MODES 3 and 4, SDM is required to ensure the reactor will be held subcritical with margin for a single withdrawn control rod. SDM is required in MODE 5 to prevent an inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies.
ACTIONS	<u>A.1</u> With SDM not within the limits of the LCO in MODE 1 or 2, SDM must be restored within 6 hours. Failure to meet the specified SDM may be caused by a control rod that cannot be inserted. The 6 hour Completion Time is acceptable, considering that the reactor can still be shut down, assuming no additional failures of control rods to insert, and the low probability of an event occurring during this interval.

(continued)

ACTIONS (continued)

B.1

If the SDM cannot be restored, the plant must be brought to MODE 3 within 12 hours, to prevent the potential for further reductions in available SDM (e.g., additional stuck control rods). The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

C.1

With SDM not within limits in MODE 3, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core.

D.1, D.2, D.3, and D.4

With SDM not within limits in MODE 4, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core. Actions must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes restoring primary containment to OPERABLE status, and primary containment isolation capability (i.e., one closed door in each primary containment air lock, and at least one primary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, Surveillances may need to be performed to restore the component to OPERABLE status.

(continued)

BASES

ACTIONS

D.1, D.2, D.3, and D.4 (continued)

In addition, at least one door in each primary containment air lock must be closed. The closed air lock door completes the boundary for control of potential radioactive releases. With the appropriate administrative controls however, the closed door can be opened intermittently for entry and exit. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the door except during the entry and exit, and assuring the door is closed after completion of the containment entry and exit. This allowance is acceptable due to the need for containment access and due to the slow progression of events which may result from inadequate SDM. Inadvertent reactor criticalities would not be expected to result in the immediate release of appreciable fission products to the containment atmosphere. Actions must continue until all requirements of this Condition are satisfied.

E.1, E.2, E.3, E.4, and E.5

With SDM not within limits in MODE 5, the operator must immediately suspend CORE ALTERATIONS that could reduce SDM, e.g., insertion of fuel in the core or the withdrawal of control rods. Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Inserting control rods or removing fuel from the core will reduce the total reactivity and are therefore excluded from the suspended actions.

Action must also be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies have been fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore do not have to be inserted.

Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes restoring primary containment to OPERABLE status, and primary containment isolation capability (i.e., one closed door in each primary containment air lock, and at least one primary containment isolation valve and associated

(continued)

BASES

ACTIONS

E.1, E.2, E.3, E.4, and E.5 (continued)

instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, Surveillances may need to be performed to restore the component to OPERABLE status. In addition, at least one door in each primary containment air lock must be closed. The closed air lock door completes the boundary for control of potential radioactive releases. With the appropriate administrative controls however, the closed door can be opened intermittently for entry and exit. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the door except during the entry and exit, and assuring the door is closed after completion of the containment entry and exit. This allowance is acceptable due to the need for containment access and due to the slow progression of events which may result from inadequate SDM. Inadvertent reactor criticalities would not be expected to result in the immediate release of appreciable fission products to the containment atmosphere. Actions must continue until all requirements of this Condition are satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

Adequate SDM must be demonstrated to ensure the reactor can be made subcritical from any initial operating condition. Adequate SDM is demonstrated within four hours after criticality following fuel movement within the reactor pressure vessel, or control rod replacement. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value must be increased by an adder, "R", which is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated BOC core reactivity. If the value of R is negative (i.e., BOC is the most reactive point in the cycle), no correction to the BOC measured value is required (Ref. 6). For the SDM demonstrations that rely solely on calculation for the determination of the highest worth control rod, additional margin (0.10% $\Delta k/k$) must be added to the SDM limit of 0.28% $\Delta k/k$ to account for uncertainties in the calculation of the highest worth control rod.

The SDM may be demonstrated during an in sequence control rod withdrawal, in which the highest worth control rod is analytically determined, or during local criticals, where the highest worth control rod is determined by testing. Local critical tests require the withdrawal of out of sequence control rods. This testing would therefore require bypassing of the Rod Pattern Control System to allow the out of sequence withdrawal, and therefore additional requirements must be met (see LCO 3.10.7, "Control Rod Testing – Operating").

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and appropriate verification.

During MODE 5, adequate SDM is also required to ensure the reactor does not reach criticality during control rod withdrawals. An evaluation of each in vessel fuel movement during fuel loading (including shuffling fuel within the core) is required to ensure adequate SDM is maintained during refueling. This evaluation ensures the intermediate loading patterns are bounded by the safety analyses for the final core loading pattern. For example, bounding analyses that demonstrate adequate SDM for the most reactive configurations during the refueling may be performed to demonstrate acceptability of the entire fuel movement sequence. For the SDM demonstrations that rely solely on calculation for the determination of the highest worth control rod, additional margin (0.10% $\Delta k/k$) must be added to

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

the SDM limit of 0.28% Δk/k to account for uncertainties in the calculation of the highest worth control rod. Spiral offload or reload sequences inherently satisfy the SR, provided the fuel assemblies are reloaded in the same configuration analyzed for the new cycle. Removing fuel from the core will always result in an increase in SDM.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. USAR, Section 15.4.9.
3. NEDO-21231, "Banked Position Withdrawal Sequence," Section 4.1, January 1977.
4. USAR, Section 15.4.1.1.
5. USAR, Section 4.3.2.4.1.
6. NEDE-24011-P-A, "GE Standard Application for Reactor Fuel, GESTAR II" (latest approved revision).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with 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. Reactivity anomaly is used as a measure of the monitored versus predicted core reactivity during power operation. The continual confirmation of core reactivity is necessary to ensure that the Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity anomaly could be the result of unanticipated changes in fuel reactivity, 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 monitored versus predicted 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 monitored and predicted 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.

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel loaded in the previous cycles provide excess positive reactivity beyond that required to sustain steady state operation at the beginning of cycle (BOC). When the reactor

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BASES

BACKGROUND (continued)	is critical at RTP, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel. The predicted core reactivity, as represented by control rod density, is calculated by a 3D core simulator code as a function of cycle exposure. This calculation is performed for projected operating states and conditions throughout the cycle. The core reactivity is determined from control rod densities for actual plant conditions and is then compared to the predicted value for the cycle exposure.
APPLICABLE SAFETY ANALYSES	Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod drop 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 anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity. The comparison between monitored and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the monitored and predicted rod density for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict rod density may not be accurate. If reasonable agreement between monitored and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the monitored rod density from the predicted rod density that develop during fuel depletion may be an indication that the assumptions of the DBA and transient analyses are no longer valid, or that an unexpected change in core conditions has occurred. Reactivity anomalies satisfy Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

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BASES (continued)

LCO

The reactivity anomaly limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. Large differences between monitored 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 difference between the monitored rod density and the predicted rod density of 1% $\Delta k/k$ has been established based on engineering judgment. A > 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

APPLICABILITY

In MODE 1, most of the control rods are withdrawn and steady state operation is typically achieved. Under these conditions, the comparison between monitored and predicted core reactivity provides an effective measure of the reactivity anomaly. In MODE 2, control rods are typically being withdrawn during a startup. In MODES 3 and 4, all control rods are fully inserted, and, therefore, the reactor is in the least reactive state, where monitoring core reactivity is not necessary. In MODE 5, fuel loading results in a continually changing core reactivity. SDM requirements (LCO 3.1.1) ensure that fuel movements are performed within the bounds of the safety analysis, and 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). The SDM test, required by LCO 3.1.1, provides a direct comparison of the monitored and predicted core reactivity at cold conditions; therefore, reactivity anomaly is not required during these conditions.

ACTIONS

A.1

Should an anomaly develop between monitored and predicted core reactivity, the core reactivity difference must be restored to within the limit to ensure continued operation is within the core design assumptions. Restoration to within the limit could be performed by an evaluation of the core design and safety analysis to determine the reason for the anomaly. This evaluation normally reviews the core

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BASES

ACTIONS

A.1 (continued)

conditions to determine their consistency with input to design calculations. Measured core and process parameters are also normally evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models may be reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA 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.

B.1

If the core reactivity cannot be restored to within the 1% Δk/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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Verifying the reactivity difference between the monitored and predicted rod density is within the limits of the LCO provides further assurance that plant operation is maintained within the assumptions of the DBA and transient analyses. The Core Monitoring System calculates the rod density for the reactor conditions obtained from plant instrumentation. A comparison of the monitored rod density to the predicted rod density at the same cycle exposure is used to calculate the reactivity difference. The comparison is required when the core reactivity has potentially changed by a significant amount. This may occur following a refueling in which new fuel assemblies are loaded, fuel assemblies are shuffled within the core, or control rods are replaced or shuffled. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Also, core

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1 (continued)

reactivity changes during the cycle. The 24 hour interval after reaching equilibrium conditions following a startup provides a reasonable period of time for performance of the Surveillance. For the purposes of this SR, the reactor is assumed to be at equilibrium conditions when steady state operations (no control rod movement or core flow changes and no reactor power changes due to changes in xenon concentration) at ≥ 80% RTP have been obtained. Although samarium has not reached equilibrium concentration in this period, any additional changes in reactivity based on changes in samarium concentration should not affect the results of this Surveillance. The 1000 MWD/T Frequency was developed, considering the relatively slow change in core reactivity with exposure and operating experience related to variations in core reactivity. This comparison requires the core to be operating at power levels which minimize the uncertainties and measurement errors, in order to obtain meaningful results. Therefore, the comparison is only done when in MODE 1.

REFERENCES

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

2. USAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Control Rod OPERABILITY

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, which is the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes to ensure that under conditions of normal operation, including anticipated operational occurrences, specified acceptable fuel design limits are not exceeded. In addition, the control rods provide the capability to hold the reactor core subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. The CRD System is designed to satisfy the requirements of GDC 26, GDC 27, GDC 28, and GDC 29, (Ref. 1).

The CRD System consists of 177 locking piston control rod drive mechanisms (CRDMs) and a hydraulic control unit for each drive mechanism. The locking piston type CRDM is a double acting hydraulic piston, which uses condensate water as the operating fluid. Accumulators provide additional energy for scram. An index tube and piston, coupled to the control rod, are locked at fixed increments by a collet mechanism. The collet fingers engage notches in the index tube to prevent unintentional withdrawal of the control rod, but without restricting insertion.

This Specification, along with LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators," ensure that the performance of the control rods in the event of a Design Basis Accident (DBA) or transient meets the assumptions used in the safety analyses of References 2, 3, 4, 5, and 6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in the evaluations involving control rods are presented in References 2, 3, 4, 5, and 6. The control rods provide the primary means for rapid reactivity control (reactor scram), for maintaining the reactor subcritical, and for limiting the potential effects of reactivity insertion events caused by malfunctions in the CRD System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The capability of inserting the control rods provides assurance that the assumptions for scram reactivity in the DBA and transient analyses are not violated. Since the SDM ensures the reactor will be subcritical with the highest worth control rod withdrawn (assumed single failure), the additional failure of a second control rod to insert could invalidate the demonstrated SDM and potentially limit the ability of the CRD System to hold the reactor subcritical. If the control rod is stuck at an inserted position and becomes decoupled from the CRD, a control rod drop accident (CRDA) can possibly occur. Therefore, the requirement that all control rods be OPERABLE ensures the CRD System can perform its intended function. The control rods also protect the fuel from damage that could result in release of radioactivity. The limits protected are the MCPR Safety Limit (SL) (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLGHR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), and the fuel damage limit (see Bases for LCO 3.1.6, "Control Rod Pattern") during reactivity insertion events. The negative reactivity insertion (scram) provided by the CRD System provides the analytical basis for determination of plant thermal limits and provides protection against fuel damage limits during a CRDA. Bases for LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6 discuss in more detail how the SLs are protected by the CRD System. Control rod OPERABILITY satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	OPERABILITY of an individual control rod is based on a combination of factors, primarily the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator OPERABILITY is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion times and therefore an inoperable accumulator does not immediately require declaring a control rod inoperable. Although not all control rods are required to be OPERABLE to

(continued)

BASES

LCO (continued)

satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the DBA and transient analyses.

APPLICABILITY

In MODES 1 and 2, the control rods are assumed to function during a DBA or transient and are therefore required to be OPERABLE in these MODES. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in Shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions. Control rod requirements in MODE 5 are located in LCO 3.9.5, "Control Rod OPERABILITY—Refueling."

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each control rod. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable control rod. Complying with the Required Actions may allow for continued operation, and subsequent inoperable control rods are governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1, A.2, A.3, and A.4</u>

A control rod is considered stuck if it will not insert (using all available insertion methods) by either CRD drive water or scram pressure. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted. The Required Actions are modified by a Note that allows a stuck control rod to be bypassed in the Rod Action Control System (RACS) to allow continued operation. SR 3.3.2.1.9 provides additional requirements when control rods are bypassed in RACS to ensure compliance with the CRDA analysis. With one withdrawn control rod stuck, the local scram reactivity rate assumptions may not be met if the stuck control rod separation criteria are not met. Therefore, verification that the separation criteria

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

are met must be performed immediately. The stuck control rod separation criteria are that the stuck control rod may not occupy a location adjacent to a "slow" control rod. The description of "slow" control rods is provided in LCO 3.1.4 "Control Rod Scram Times". In addition, the control rod must be disarmed within 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable amount of time to perform the Required Action in an orderly manner. Isolating the control rod from scram prevents damage to the CRDM. The control rod can be

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

isolated from scram by isolating the hydraulic control unit from scram and normal drive and withdraw pressure, yet still maintain cooling water to the CRD. A control rod can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rod can be disarmed by disconnecting power from all four directional control valve solenoids.

Monitoring of the insertion capability for each withdrawn control rod must also be performed within 24 hours. SR 3.1.3.2 performs periodic tests of the control rod control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. The allowed Completion Time of 24 hours provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests. Required Action A.2 has a modified time zero Completion Time. The 24 hour Completion Time for this Required Action starts when the withdrawn control rod is discovered to be stuck and THERMAL POWER is greater than the actual low power setpoint (LPSP) of the rod pattern controller (RPC), since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RPC (LCO 3.3.2.1, "Control Rod Block Instrumentation").

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion an additional control rod would have to be assumed to have failed to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod

(continued)

BASES

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach and maintain MODE 3 conditions (Ref. 7).

B.1

With two or more withdrawn control rods stuck, the plant should be brought to MODE 3 within 12 hours. Isolating the control rod from scram prevents damage to the CRDM. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in the withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. With a control rod not coupled to its associated drive mechanism, insert the control rod drive mechanism to accomplish recoupling. Verify recoupling by withdrawing the control rod and observing any indicated response of the nuclear instrumentation and demonstrating that the control rod drive will not go to the overtravel position. Required Action C.1 is modified by a Note that allows control rods to be bypassed in the RACS if required to allow insertion of the inoperable control rods and continued operation. SR 3.3.2.1.9 provides additional requirements when the control rods are bypassed to ensure compliance with the CRDA analysis.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 19.0% RTP, the standard banked position withdrawal sequence (BPWS) analysis (Ref. 7) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Required Action D.1 is utilized when the control rods that are violating the standard BPWS separation criteria cannot be restored to an OPERABLE condition. Required Action D.1, "Restore compliance with BPWS", means to provide an analysis which demonstrates that the control rod worths of a proposed or existing rod pattern are no more than the control rod worths determined in the standard BPWS analysis. Under Required Action D.1, even after compliance with BPWS is restored through new analysis, the control rods remain inoperable per LCO 3.1.6 unless they can be moved to meet the standard separation criteria (see Required Action D.2). Required Action D.2, "Restore control rod to OPERABLE status", means to move one or both control rods back into pattern such that they can be re-declared OPERABLE, or, if the rod is inoperable for reasons other than a pattern deviation, resolve that inoperability and then move the rod to be in compliance with the standard BPWS analysis. If the requirements for use of the optional BPWS control rod insertion process contained in Reference 8 are being followed for a plant shutdown, the plant is considered to be in compliance with BPWS requirements, and Condition D need not be entered.

A Note has been added to the Condition to clarify that the Condition is not applicable when > 19.0% RTP since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

(continued)

BASES

ACTIONS (continued)

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met or nine or more inoperable control rods exist, 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 12 hours. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 19.0% RTP (i.e., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined, to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of at least one OPERABLE position indicator, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The Surveillance Frequency is controlled under the Surveillance Control Program.

SR 3.1.3.2

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. Observation of changes in indicated control rod position provides evidence that the control rod position indication is OPERABLE. This ensures the control rod is not stuck and is free to insert on a scram signal. When plant procedures permit, this SR may also be met by rod scram. This Surveillance is not required when THERMAL POWER is less than or equal to the actual LPSP of the RPC since the notch insertions may not be compatible with the requirements of the BPWS (LCO 3.1.6) and the RPC (LCO 3.3.2.1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. At any time, if a control rod is immovable, a determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

SR 3.1.3.3

Verifying the scram time for each control rod to notch position 13 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.3 (continued)

This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3 and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.4

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity, since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed anytime a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This includes control rods inserted one notch and then returned to the "full out" position during the performance of SR 3.1.3.2. Until the control rod reaches the "full out" position where coupling can be verified, the nuclear instrumentation is observed for any indicated response during withdrawal. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26, GDC 27, GDC 28, and GDC 29.
2. USAR, Section 4.3.2.5.5.
3. USAR, Section 4.6.1.1.2.5.3.
4. USAR, Section 5.2.2.2.2.3.
5. USAR, Section 15.4.1.
6. USAR, Section 15.4.9.
7. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.
8. NEDO-33091-A, Revision 2, "Improved BPWS Control Rod Insertion Process," July 2004.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System controls reactivity changes during abnormal operational transients to ensure that specified acceptable fuel design limits are not exceeded (Ref. 1). The control rods are scrammed by positive means, using hydraulic pressure exerted on the CRD piston.

When a scram signal is initiated, control air is vented from the scram valves, allowing them to open by spring action. Opening the exhaust valves reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator or reactor pressure to the bottom of the piston. Since the notches in the index tube are tapered on the lower edge, the collet fingers are forced open by cam action, allowing the index tube to move upward without restriction because of the high differential pressure across the piston. As the drive moves upward and accumulator pressure drops below the reactor pressure, a ball check valve opens, letting the reactor pressure complete the scram action. If the reactor pressure is low, such as during startup, the accumulator will fully insert the control rod within the required time without assistance from reactor pressure.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 2, 3, 4, and 5. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Other distributions of scram times (e.g., several control rods scramming slower than the average time, with several control rods scramming faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The scram function of the CRD System protects the MCPR Safety Limit (SL) (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded. Above 950 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL during the analyzed limiting power transient. Below 950 psig, the scram function is assumed to perform during the control rod drop accident (Ref. 6) and, therefore, also provides protection against violating fuel damage limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Control Rod Pattern"). For the reactor vessel overpressure protection analysis, the scram function, along with the safety/relief valves, ensure that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control rod scram times satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The scram times specified in Table 3.1.4-1 are required to ensure that the scram reactivity assumed in the DBA and transient analysis is met. To account for single failure and "slow" scramming control rods, the scram times specified in Table 3.1.4-1 are faster than those assumed in the design basis analysis. The scram times have a margin to allow up to 7.5% of the control rods (i.e., 177 x 7.5% = 13) to have scram times that exceed the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens ("dropout") as the index tube travels upward. Verification of the specified scram times in Table 3.1.4-1 is accomplished through measurement of the "dropout" times.

(continued)

BASES

LCO (continued)

To ensure that local scram reactivity rates are maintained within acceptable limits, no "slow" control rods may occupy a location adjacent to another "slow" control rod or adjacent to a withdrawn stuck control rod.

Table 3.1.4-1 is modified by two Notes, which state control rods with scram times not within the limits of the Table are considered "slow" and that control rods with scram times > 7 seconds are considered inoperable as required by SR 3.1.3.3.

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, the control rods are not able to be withdrawn since the reactor mode switch is in the shutdown position and a control rod block is applied. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY-Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analyses. Therefore, 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The four SRs of this LCO are modified by a Note stating that during a single control rod scram time surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated (i.e., charging valve closed), the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 950 psig demonstrates acceptable scram times for the transients analyzed in References 3 and 4.

Scram insertion times increase with increasing reactor pressure because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure greater than 950 psig ensures that the scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure scram time testing is performed within a reasonable time following a shutdown ≥ 120 days, all control rods are required to be tested before exceeding 40% RTP. This Frequency is acceptable, considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the other required scram time tests of control rods (those performed on rods potentially affected either by fuel movement within their core cell or by work on control rods or the CRD System that could affect their scram time).

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains "representative" if no more than 7.5% of the control rods in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.2 (continued)

the tested sample are determined to be "slow." If more than 7.5% of the sample is declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (e.g., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods (throughout the core, from all surveillances) exceeds the LCO limit. For planned testing, the control rods selected for the sample shall be different for each test in a cycle. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data were previously tested in a sample. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures from zero to the maximum permissible pressure. The scram testing must be performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate that the affected control rod is still within acceptable limits. For control rod drive scram time testing at less than 950 psig, the following scram times to notch position 13 shall be used as acceptance criteria:

0 psig - 0.94 seconds

600 psig - 1.13 seconds

950 psig - 1.40 seconds

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.3 (continued)

For intermediate reactor steam dome pressures, the scram time criteria are determined by linear interpolation. The limits for reactor pressures < 950 psig are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 950 psig. Limits for ≥ 950 psig are found in Table 3.1.4-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7 second limit of Table 3.1.4-1 Note 2, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times include (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator isolation valve, or check valves in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability of testing the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

When work that could affect the scram insertion time is performed on a control rod or the CRD System, or when fuel movement within the reactor pressure vessel occurs, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 950 psig. Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 will be satisfied with one test. For a control rod affected by work performed while shut down, however, a zero pressure and a high pressure test may be required. This testing ensures that the control rod scram performance is acceptable for operating reactor pressure conditions prior to withdrawing the control rod for continued operation. Alternatively, a test during hydrostatic pressure testing could also satisfy both criteria. When fuel movement within the reactor pressure vessel occurs, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage, it is expected that all control rods will be affected.

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BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.1.4.4</u> (continued) The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability of testing the control rod at the different conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 10. 2. USAR, Section 4.3.2.5.5. 3. USAR, Section 4.6.1.1.2.5.3. 4. USAR, Section 5.2.2.2.2.3. 5. USAR, Section 15.4.1. 6. USAR, Section 15.4.9.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Control Rod Scram Accumulators

BASES

BACKGROUND

The control rod scram accumulators are part of the Control Rod Drive (CRD) System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a control rod at any reactor vessel pressure. The accumulator is a hydraulic cylinder with a free floating piston. The piston separates the water used to scram the control rods from the nitrogen, which provides the required energy. The scram accumulators are necessary to scram the control rods within the required insertion times of LCO 3.1.4, "Control Rod Scram Times."

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 1, 2, 3, and 4. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. OPERABILITY of each individual control rod scram accumulator, along with LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.4, ensures that the scram reactivity assumed in the DBA and transient analyses can be met. The existence of an inoperable accumulator may invalidate prior scram time measurements for the associated control rod.

The scram function of the CRD System, and, therefore, the OPERABILITY of the scram accumulators, protects the MCPR Safety Limit (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). Also, the scram function at low reactor vessel pressure (i.e., startup conditions) provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Control Rod Pattern").

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Control rod scram accumulators satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.
APPLICABILITY	In MODES 1 and 2, the scram function is required for mitigation of DBAs and transients and, therefore, the scram accumulators must be OPERABLE to support the scram function. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in the shutdown position and a control rod block is applied. This provides adequate requirements for control rod scram accumulator OPERABILITY under these conditions. Requirements for scram accumulators in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY-Refueling."
ACTIONS	The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the Required Actions for each Condition provide appropriate compensatory action for each affected control rod. Complying with the Required Actions may allow for continued operation and subsequent affected control rods governed by subsequent Condition entry and application of associated Required Actions. <u>A.1 and A.2</u> With one control rod scram accumulator inoperable and the reactor steam dome pressure ≥ 600 psig, the control rod may be declared "slow," since the control rod will still scram at the reactor operating pressure but may not satisfy the required scram times in Table 3.1.4-1. Required Action A.1 is modified by a Note, which clarifies that declaring the control rod "slow" is only applicable if the associated control scram time was within the limits of Table 3.1.4-1 during the last scram time test. Otherwise, the control rod

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

would already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action A.2) and LCO 3.1.3 entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 8 hours is considered reasonable, based on the large number of control rods available to provide the scram function and the ability of the affected control rod to scram only with reactor pressure at high reactor pressures.

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

With two or more control rod scram accumulators inoperable and reactor steam dome pressure ≥ 600 psig, adequate pressure must be supplied to the charging water header by an operating CRD pump. With inadequate charging water pressure, all of the accumulators could become inoperable, resulting in a potentially severe degradation of the scram performance. Therefore, within 20 minutes from discovery of charging water header pressure < 1520 psig concurrent with Condition B, adequate charging water header pressure must be restored. The discovery of low charging water header pressure can occur in many ways such as by monitoring charging water header pressure instrumentation, or by attempting to move a control rod one notch. The allowed Completion Time of 20 minutes is considered a reasonable time to place a CRD pump into service to restore the charging header pressure, if required. This Completion Time also recognizes the ability of the reactor pressure alone to fully insert all control rods.

The control rod may be declared "slow," since the control rod will still scram using only reactor pressure, but may not satisfy the times in Table 3.1.4-1. Required Action B.2.1 is modified by a Note indicating that declaring the control rod "slow" is only applicable if the associated control scram time was within the limits of Table 3.1.4-1 during the last scram time test. Otherwise, the control rod

(continued)

BASES

ACTIONS

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

would already be considered "slow" and the further degradation of scram performance with an inoperable scram accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action B.2.2) and LCO 3.1.3 entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is considered reasonable, based on the ability of only the reactor pressure to scram the control rods and the low probability of a DBA or transient occurring while the affected accumulators are inoperable.

C.1 and C.2

With one or more control rod scram accumulators inoperable and the reactor steam dome pressure < 600 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor steam dome pressure < 600 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become severely degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 1520 psig, concurrent with Condition C, all control rods associated with inoperable accumulators must be verified to be fully inserted. Withdrawn control rods with inoperable scram accumulators may fail to scram under these low pressure conditions. The associated control rods must also be declared inoperable within 1 hour (Required Action C.2) and LCO 3.1.3 entered. The allowed Completion Time of 1 hour is reasonable for Required Action C.2, considering the low probability of a DBA or transient occurring during the time the accumulator is inoperable.

(continued)

BASES

ACTIONS (continued)

D.1

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with the loss of the CRD pump (Required Actions B.1 and C.1) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the Required Action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the scram accumulator pressure be checked periodically to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 1520 psig is well below the expected pressure of 1750 psig (Ref. 2). Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 4.3.2.5.5.
2. USAR, Section 4.6.1.1.2.5.3.
3. USAR, Section 5.2.2.2.2.3.
4. USAR, Section 15.4.1.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Rod Pattern

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod pattern controller (RPC) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed from the condition of all control rods fully inserted up to the low power setpoint (LPSP). The sequences effectively limit the potential amount of reactivity addition that could occur in the event of a control rod drop accident (CRDA).

This Specification ensures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1 and 2. |

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RPC (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage, which could result in undue release of radioactivity. Since the failure consequences for UO_2 have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 3), the fuel damage limit of 280 cal/gm provides a margin of safety from significant core damage, which would result in release of radioactivity (Refs. 4 and 5). Generic evaluations (Ref. 6) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 7) and the calculated offsite doses will be well within the required limits (Ref. 5).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in Reference 2 follow the standard banked position withdrawal sequence (BPWS) analysis described in Reference 8. The BPWS is applicable from the condition of all control rods fully inserted to 19.0% RTP (Ref. 1). For the standard BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are defined to minimize the maximum incremental control rod worths without being overly restrictive during normal plant operation. The standard BPWS analysis (Ref. 8) also evaluated the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods.

When performing a shutdown of the plant, an optional BPWS control rod sequence (Refs. 10, 11, and 12) may be used provided that all withdrawn control rods have been confirmed to be coupled. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled. When using the Reference 10 control rod insertion process, the rod pattern controller may be bypassed as permitted by the Applicability Note for the Rod Pattern Controller in Table 3.3.2.1-1. No control rod withdrawals are permitted while using this process.

In order to use the Reference 10 BPWS shutdown process, an extra check is required in order to consider a control rod to be "confirmed" to be coupled. This extra check ensures that no Single Operator Error can result in an incorrect coupling check, i.e., the coupling confirmation is performed once with two operators involved who both verify the rod is coupled, or the coupling confirmation is performed on two separate occasions. For purposes of this shutdown process, the method for confirming that control rods are coupled varies depending on the position of the control rod in the core. Details on this coupling confirmation requirement are provided in Sections 4 and 5 of Reference 10. If the requirements for use of the BPWS control rod insertion process contained in Reference 10 are followed, the plant is considered to be in compliance with BPWS requirements, as required by LCO 3.1.6.

Rod pattern control satisfies the requirements of Criterion 3 of the NRC Final Policy Statement on Technical Specification improvements (58 FR 39132).

(continued)

BASES (continued)

LCO	Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the standard BPWS analysis. Compliance with the optional BPWS control rod insertion process prevents a CRDA from occurring. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.
APPLICABILITY	In MODES 1 and 2, when THERMAL POWER is ≤ 19.0% RTP, the CRDA is a Design Basis Accident (DBA) and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 19.0% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 1). In MODES 3, 4, and 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, action may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of "double notching," drifting from a control rod drive cooling water transient, leaking scram valves, rods inserted for the purpose of suppressing a fuel defect, conducting single rod scram time testing (Ref. 9), or a power reduction to ≤ 19.0% RTP before establishing the correct control rod pattern. The number of OPERABLE control rods not in compliance with the prescribed sequence is limited to eight to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence. When the control rod pattern is not in compliance with the prescribed sequence, all control rod movement should be stopped except for moves needed to correct the control rod pattern, or scram if warranted.

Required Action A.1 is modified by a Note, which allows control rods to be bypassed in Rod Action Control System (RACS) in accordance with SR 3.3.2.1.9 to allow the affected control rods to be returned to their correct position. This ensures that the control rods will be moved to the correct position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. OPERABILITY of control rods is determined by compliance with LCO 3.1.3; LCO 3.1.4, "Control Rod Scram Times"; and LCO 3.1.5, "Control Rod Scram Accumulators." The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out of sequence control rods and the low probability of a CRDA occurring during the time the control rods are out of sequence.

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

withdrawals have. Required Action B.1 is modified by a Note that allows the affected control rods to be bypassed in RACS in accordance with SR 3.3.2.1.9 to allow insertion only.

With nine or more OPERABLE control rods not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the reactor mode switch in shutdown, the reactor is shut down, and therefore does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is periodically verified to be in compliance with the BPWS, ensuring the assumptions of the CRDA analyses are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The RPC provides control rod blocks to enforce the required control rod sequence and is required to be OPERABLE when operating at ≤ 19.0% RTP.

REFERENCES

1. "Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners Group, July 1987.

2. USAR, Section 15.4.9.

3. NUREG-0979, "NRC Safety Evaluation Report Related to the Final Design Approval of the GESSAR II BWR/6 Nuclear Island Design, Docket No. 50-447," Section 4.2.1.3.2, April 1983.

4. NUREG-0800, "Standard Review Plan," Section 15.4.9, "Radiological Consequences of Control Rod Drop Accident (BWR)," Revision 2, July 1981.

(continued)

BASES

REFERENCES

5. 10 CFR 50.67, "Accident Source Term."

6. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

7. ASME, Boiler and Pressure Vessel Code.

8. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

9. USAR 7.6.1.5.C.

10. NEDO-33091-A, Revision 2, ''Improved BPWS Control Rod Insertion Process,'' July 2004.

11. USAR 4.3.2.5.2.

12. USAR 7.6.1.5.B.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

To meet General Design Criterion 26, the SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive xenon free state without taking credit for control rod movement. In addition, the SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System consists of a boron solution storage tank, two positive displacement pumps and two explosive valves, which are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the high pressure core spray system sparger.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the control room, as directed by the Emergency Operating Procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject a quantity of boron that produces a concentration of at least 816 ppm of natural boron in the reactor core at 68°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional amount of boron equal to 25% of the amount cited above is added (Ref. 2). The concentration versus volume limits in Figure 3.1.7-1 are calculated such that the required concentration is achieved accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount that is above the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

pump suction low level trip in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected.

Credit is also taken for use of the SLC System in the licensing basis radiological calculations for an accident that causes severe core damage. In such an event, radioactive iodine (and other fission products other than the noble gases) would be released into the drywell and containment atmosphere primarily in an aerosol (particulate) form, such as cesium iodide and other iodide forms. These iodide compounds will settle out, or be sprayed out of the containment atmosphere by the RHR Containment Sprays. Without any pH control of the water in the reactor vessel and suppression pool, large fractions of the dissolved iodides could be converted to elemental iodine and be re-evolved into the containment atmosphere. However, if the pH is controlled and maintained at a value of 7 or greater, very little (less than 1%) of the dissolved iodides will be converted and re-evolved. Therefore, the SLC system, which contains a buffering solution that raises the pH of water, would be injected. This solution would mix in the reactor vessel and suppression pool water, and ensure that long-term vessel and suppression pool pH levels are maintained greater than or equal to 7.

The SLC System satisfies Criterion 3 of 10 CFR 50.36 for its post-LOCA function of pH buffering, and was considered to meet Criterion 4 because operating experience and probabilistic risk assessment have generally shown it to be important to public health and safety.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control, independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE, each containing an OPERABLE pump, an explosive valve and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in the shutdown position and a control rod block is applied. This provides adequate controls to ensure the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE during these conditions, when only a single control rod can be withdrawn.

ACTIONS

A.1

With one SLC subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the OPERABLE subsystem is adequate to perform the shutdown function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced SLC System shutdown capability. The 7 day Completion Time is based on the availability of an

(continued)

BASES

ACTIONS

A.1 (continued)

OPERABLE subsystem capable of performing the intended SLC System function and the low probability of a Design Basis Accident (DBA) or transient occurring concurrent with the failure of the Control Rod Drive System to shut down the reactor.

B.1

With two SLC subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable, based on the low probability of a DBA or transient occurring concurrent with the failure of the Control Rod Drive System to shut down the reactor.

C.1

If any Required Action and associated Completion Time is 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 MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1, SR 3.1.7.2, and SR 3.1.7.3

SR 3.1.7.1 through SR 3.1.7.3 verify certain characteristics of the SLC System (e.g., the volume and temperature of the borax-boric acid solution in the storage tank, and temperature of the pump suction piping), thereby ensuring the SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure the proper borated solution and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. With regards to Figure 3.1.7-1, operation within the "MARGIN" region of the figure is acceptable and ensures the ability of the SLC System to meet SR 3.1.7.1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure proper operation will occur if required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.6 verifies each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual, power operated, and automatic valves in the SLC System flow path ensures that the proper flow paths will exist for system operation. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve controls. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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 positions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.7.5

This Surveillance requires an examination of the borax-boric acid solution by using chemical analysis to ensure the proper concentration of boron exists in the storage tank. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Additionally, SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to establish that the boron solution concentration is within the specified limits. This Surveillance must be performed anytime the solution

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.5 (continued)

temperature is restored to ≥ 70°F, to ensure no significant boron precipitation occurred.

SR 3.1.7.7

Demonstrating each SLC System pump develops a flow rate ≥ 32.4 gpm at a discharge pressure ≥ 1220 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the borax-boric acid solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve, and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.8 and SR 3.1.7.9 (continued)

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the boron solution. An acceptable method for verifying that the suction piping is unblocked is to pump from the storage tank to the test tank and then draining and flushing the pipe with demineralized water. The test may be performed by any series of sequential, overlapping, or total flow path steps such that the entire flow path is included. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If, in performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored to ≥ 70°F.

REFERENCES

1. 10 CFR 50.62.
2. USAR, Section 9.3.5.3.
3. USAR, Section 15.6.5.5.1.8

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. The SDV consists of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two headers and two instrument volumes, each receiving approximately one half of the control rod drive (CRD) discharges. The two instrument volumes are connected to a common drain line with two valves in series. Each header is connected to a common vent line with two valves in series. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference 1.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all the control rods are capable of scramming. The primary function of the SDV is to limit the amount of reactor coolant discharged during a scram. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to:

a. Close during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite doses remain within the limits of 10 CFR 50.67 (Ref. 2); and

b. Open on scram reset to maintain the SDV vent and drain path open so there is sufficient volume to accept the reactor coolant discharged during a scram.

Isolation of the SDV can also be accomplished by manual closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite doses are well within the licensing basis dose limits, and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves also

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

allow continuous drainage of the SDV during normal plant operation to ensure the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level exceeds a specified setpoint. The setpoint is chosen such that all control rods are inserted before the SDV has insufficient volume to accept a full scram.

SDV vent and drain valves satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The OPERABILITY of all SDV vent and drain valves ensures that, during a scram, the SDV vent and drain valves will close to contain reactor water discharged to the SDV piping. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to be open to ensure that a path is available for the SDV piping to drain freely at other times.

APPLICABILITY

In MODES 1 and 2, scram may be required, and therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in the shutdown position and a control rod block is applied. Also, during MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram.

ACTIONS

The ACTIONS table is modified by Note 1 indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS table is also modified by Note 2 stating that an isolated line may be unisolated under administrative control to allow draining and venting of the SDV. When a line is

(continued)

BASES

ACTIONS (continued)

isolated, the potential for an inadvertent scram due to high SDV level is increased. During these periods, the line may be unisolated under administrative control. This allows depressurization of the SDV and any accumulated water in the SDV to be drained, to preclude a reactor scram on SDV high level. This is acceptable, since the administrative controls ensure the line can be isolated quickly, by a dedicated operator, if a scram occurs with the line not isolated.

A.1

When one SDV vent or drain valve is inoperable in one or more lines, the associated line must be isolated to contain the reactor coolant during a scram. The 7 day Completion Time is reasonable, given the level of redundancy in the lines and the low probability of a scram occurring during the time the valve(s) are inoperable and the line is not isolated. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. Since the SDV is still isolable, the affected SDV line may be opened. This allows depressurization of the SDV and any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

B.1

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram.

The 8 hour Completion Time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and unlikelihood of significant CRD seal leakage.

C.1

If any Required Action and associated Completion Time is 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

(continued)

BASES

ACTIONS

C.1 (continued)

brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

During normal operation, the SDV vent and drain valves should be in the open position (except when performing SR 3.1.8.2) to allow for drainage of the SDV piping. Verifying that each valve is in the open position ensures that the SDV vent and drain valves will perform their intended function during normal operation. This SR does not require any testing or valve manipulation; rather, it involves verification that the valves are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.2

During a scram, the SDV vent and drain valves should close to contain the reactor water discharged to the SDV piping. Cycling each valve through its complete range of motion (closed and open) ensures that the valve will function properly during a scram. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.3

SR 3.1.8.3 is an integrated test of the SDV vent and drain valves to verify total system performance. After receipt of a simulated or actual scram signal, the closure of the SDV vent and drain valves is verified. The closure time of 30 seconds after a receipt of a scram signal is based on the

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.1.8.3 (continued) bounding leakage case evaluated in the accident analysis. Similarly, after receipt of a simulated or actual scram reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3, "Control Rod OPERABILITY," overlap this Surveillance to provide complete testing of the assumed safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 4.6.1.1.2.4.2.5. 2. 10 CFR 50.67, "Accident Source Term." 3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

BASES

BACKGROUND

The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that the peak cladding temperature (PCT) during the postulated design basis loss of coolant accident (LOCA) does not exceed the limits specified in 10 CFR 50.46.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel design limits are presented in the USAR, Chapters 4, 6, and 15, and in References 1 and 2. The analytical methods and assumptions used in evaluating LOCA and normal operations that determine APLHGR limits are presented in USAR, Chapters 4, 6, and 15, and in References 1, 2, 3, and 4.

APLHGR limits are developed as a function of exposure and the various operating core flow and power states to ensure adherence to 10 CFR 50.46 during the limiting LOCA. Flow dependent APLHGR limits are determined using the three dimensional BWR simulator code (Ref. 5) to analyze slow flow runout transients. The flow dependent multiplier, $MAPFAC_f$, is dependent on the maximum core flow runout capability. $MAPFAC_f$ curves are provided based on the maximum credible flow runout transient for Loop Manual and Non Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control. Non Loop Manual operational modes allow simultaneous runout of both loops because a single controller regulates core flow.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Based on analyses of limiting plant transients (other than core flow increases) over a range of power and flow conditions, power dependent multipliers, $MAPFAC_p$, are also generated. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram signals are bypassed, both high and low core flow $MAPFAC_p$ limits are provided for operation at power levels between 23.8% RTP and the previously mentioned bypass power level. The exposure dependent APLHGR limits are reduced by $MAPFAC_p$ and $MAPFAC_f$ at various operating conditions to ensure that all fuel design criteria are met for normal operation and LOCA. A complete discussion of the analysis code is provided in Reference 6. The ECCS/LOCA analysis assumes the existence of MAPFAC.

LOCA analyses are performed to ensure that the above determined APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A discussion of the analysis code is provided in Reference 7. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. The APLHGR limits specified are equivalent to the LHGR of the highest powered fuel rod assumed in the LOCA analysis divided by its local peaking factor.

For single recirculation loop operation, the MAPFAC multiplier is limited to a maximum value which is specified in the COLR. This multiplier is due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA.

The APLHGR satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

The APLHGR limits specified in the COLR are a function of exposure and are a result of DBA analyses. For two recirculation loops operating, the limit is determined by multiplying the smaller of the $MAPFAC_f$ and $MAPFAC_p$ factors times the exposure dependent APLHGR limits. With only one recirculation loop in operation, in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating," the limit is determined by multiplying the exposure dependent APLHGR limit by the smallest of $MAPFAC_f$, $MAPFAC_p$, and the limiting value specified for single recirculation loop operation in the COLR, which has been determined by a specific single recirculation loop analysis (Ref. 2).

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA analyses that are assumed to occur at high power levels. Design calculations and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 4.7% to 14.2% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) scram function provides rapid scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels < 23.8% RTP, the reactor operates with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limit, an assumption regarding an initial condition of the DBA analysis may not be met. Therefore, prompt action is taken to restore the APLHGR(s) to within the required limit(s) such that the plant will be operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limit and is acceptable based on the low probability of a LOCA occurring simultaneously with the APLHGR out of specification.

(continued)

BASES

ACTIONS (continued)

B.1

If the APLHGR cannot be restored to within its required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 23.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23.8% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 23.8% RTP and then periodically thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 12 hour allowance after THERMAL POWER ≥ 23.8% RTP is achieved, is acceptable given the large inherent margin to operating limits at low power levels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR-II" (latest approved revision).
2. USAR, Chapter 15, Appendix 15B.
3. USAR, Chapter 15, Appendix 15F.
4. USAR, Chapter 15, Appendix 15E.
5. NEDE-30130-P-A, "Steady State Nuclear Methods," April 1985.

(continued)

BASES

REFERENCES (continued)

6. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

7. USAR, Section 6.3

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs), and that 99.9% of the fuel rods avoid boiling transition if the limit is not violated. Although fuel damage does not necessarily occur if a fuel rod actually experiences boiling transition (Ref. 1), the critical power at which boiling transition is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in the USAR, Chapters 4, 6, and 15, and References 2, 3, 4, 5, and 6. To ensure that the MCPR Safety Limit (SL) is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR). When the largest ΔCPR is combined with the $SLMCPR_{99.9\%}$, the required operating limit MCPR is obtained. $MCPR_{99.9\%}$ is determined to ensure more than 99.9% of the fuel rods in the core are not susceptible to boiling transition using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the $MCPR_{99.9\%}$ calculation are given in Reference 2. Reference 2 also includes a tabulation of the uncertainties and the nominal values of the parameters used in the $MCPR_{99.9\%}$ statistical analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits are derived from the $MCPR_{99.9\%}$ value and the transient analysis, and are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Refs. 4, 5, and 6).

Flow dependent MCPR limits ($MCPR_f$) are determined by steady state thermal hydraulic methods using the three dimensional BWR simulator code (Ref. 7). $MCPR_f$ curves are provided based on the maximum credible flow runout transient for Loop Manual and Non Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control. Non Loop Manual operational modes allow simultaneous runout of both loops because a single controller regulates core flow.

Power dependent MCPR limits ($MCPR_p$) are determined by approved transient analysis models (Ref. 8). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 23.8% RTP and the previously mentioned bypass power level.

Pressure Regulator Out of Service (PROOS) option is an analysis using the Pressure Regulator Downscale Failure (PRDF) at off-rated conditions. At full power, the PRDF is bounded by other pressurization transients. However, as the reactor power at the beginning of the transient decreases, the impact of the PRDF to MCPR increases.

During a PRDF transient, the pressure regulator closes the turbine control valves. This increases pressure, which increases power in the reactor. When the reactor is at full power, the pressure and power increases quickly, causing a SCRAM. As the reactor power is decreased, the power is further from the SCRAM setpoint so it takes more time to SCRAM. This longer time to SCRAM increases the amount of specific heat in the fuel and impacts the CPR. There is a range of initial reactor power where the CPR is no longer bounded by the normal $MCPR_p$ limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	There are two independent channels in the pressure regulating system and the PRDF transient is not applicable when both channels are operable. The COLR identifies the range of the modified MCPR limits and the new limits. These limits may be incorporated by either a revision to the monitoring system or appropriate administrative limits. The MCPR satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The MCPR operating limits specified in the COLR ($MCPR_{99.9\%}$ values, $MCPR_f$ values, and $MCPR_p$ values) are the result of the Design Basis Accident (DBA) and transient analysis. The MCPR operating limits are determined by the larger of the $MCPR_f$ and $MCPR_p$ limits, which are based on the $MCPR_{99.9\%}$ limit specified in the COLR.
APPLICABILITY	The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 23.8% RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 23.8% RTP is unnecessary due to the large inherent margin that ensures that the $MCPR_{95/95}$ is not exceeded even if a limiting transient occurs.

(continued)

BASES

APPLICABILITY (continued)

Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 23.8% RTP. This trend is expected to continue to the 4.7% to 14.2% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) provides rapid scram initiation for any significant power increase transient, thereby effectively removing any MCPR compliance concern in MODE 2. Therefore, at THERMAL POWER levels < 23.8% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR exceeds the required limit, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action is taken to restore the MCPR(s) to within the required limit(s) such that the plant will be operating within analyzed conditions. The 2 hour Completion Time is sufficient to restore the MCPR(s) to within its limit and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within the required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 23.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23.8% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

MCPRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 23.8% RTP and then periodically thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 12 hour allowance after THERMAL POWER ≥ 23.8% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. NUREG-0562, "Fuel Rod Failures As A Consequence of Nucleate Boiling or Dryout," June 1979.
2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR-II" (latest approved revision).
3. Supplemental Reload Licensing Report for Perry Nuclear Power Plant Unit 1, Reload 3 Cycle 4.
4. USAR, Chapter 15, Appendix 15B.
5. USAR, Chapter 15, Appendix 15C.
6. USAR, Chapter 15, Appendix 15D.
7. NEDE-30130-P-A, "Steady State Nuclear Methods," April 1985.
8. NEDE-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. Limits on the LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs), and to ensure that the peak clad temperature (PCT) during postulated Design Basis Loss of Coolant Accident (LOCA) does not exceed the limits specified in 10 CFR 50.46. Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure or inability to cool the fuel does not occur during the anticipated operating conditions identified in USAR Chapters 6 and 15.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the fuel design limits are presented in the USAR, Chapters 4, 6, and 15, and in References 1 and 2. The analytical methods and assumptions used in evaluating AOOs and normal operation that determine the LHGR limits are presented in USAR Chapters 4 and 15, and in References 1 and 2. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20 and 50. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during continuous operation with LHGR up to the operating limit LHGR specified in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The analysis also includes allowances for short term transient operation above the operating limit to account for AOOs, plus an allowance for densification power spiking. The LHGR limits are developed as a function of exposure and the various operating core flow and power states to ensure adherence to fuel design limits during the limiting AOOs(Refs. 3 and 4). Flow dependent Thermal-Mechanical LHGR Limits are determined using the three dimensional BWR simulator code (Ref. 5) to analyze slow flow runout transients. The flow dependent multiplier for the Thermal-Mechanical LHGR Limits is dependent on the maximum core flow runout capability. Thermal-Mechanical LHGR Limit curves are provided based on the maximum credible flow runout transient for Loop Manual and Non Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control. Non Loop Manual operational modes allow simultaneous runout of both loops because a single controller regulates core flow. The LHGR limits are primarily derived from fuel design evaluations and transient analyses that are assumed to occur at high power levels. Design calculations and operating experience have shown that as power is reduced, the margin to the required LHGR limits increases. This trend continues down to the power range of 4.7% to 14.2% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) scram function provides rapid scram initiation during any significant transient, thereby effectively removing any LHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels < 23.8% RTP, the reactor operates with substantial margin to the LHGR limits; thus, this LCO is not required The LHGR satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.

(continued)

BASES (continued)

APPLICABILITY	The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At THERMAL POWER levels < 23.8% RTP, the reactor is operating with substantial margin to the LHGR limits and this LCO is not required.
ACTIONS	A.1 If any LHGR exceeds the required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action is taken to restore the LHGR(s) to within required limit(s) such that the plant will be operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the LHGR(s) to within its limit and is acceptable based on the low probability of a transient or Design Basis LOCA occurring simultaneously with the LHGR out of specification. B.1 If the LHGR cannot be restored to within its required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 23.8% RTP within 4 hours. The allowed

(continued)

BASES

ACTIONS	B.1 (continued) Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 23.8% RTP in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.2.3.1 The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 23.8% RTP and then periodically thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 12 hour allowance after THERMAL POWER ≥ 23.8% RTP is achieved, is acceptable given the large inherent margin to operating limits at lower power levels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. NUREG-0800, "Standard Review Plan," Section 4.2, II.A.2(g), Revision 2, July 1981. 2. USAR, Chapter 15, Appendix 15B. 3. USAR, Chapter 15, Appendix 15F. 4. USAR, Chapter 15, Appendix 15E. 5. NEDE-30130-P-A, "Steady State Nuclear Methods," April 1985.

B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a reactor scram when one or more monitored parameters exceed their specified limit, to preserve the integrity of the fuel cladding and the Reactor Coolant System (RCS), and minimize the energy that must be absorbed following a loss of coolant accident (LOCA). This can be accomplished either automatically or manually.

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters, and equipment performance. The LSSS are defined in this Specification as the Allowable Values, which, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits, including Safety Limits (SLs), during Design Basis Accidents (DBAs).

The RPS, as shown in the USAR, Figure 7.2-1 (Ref. 1), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a reactor scram. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level; reactor vessel pressure; neutron flux; main steam line isolation valve position; turbine control valve (TCV) fast closure, trip oil pressure—low; turbine stop valve (TSV) closure; drywell pressure; and scram discharge volume (SDV) water level; as well as reactor mode switch in shutdown position and manual scram signals. There are at least four redundant sensor input signals from each of these parameters (with the exception of the reactor mode switch in shutdown scram signal). Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When a setpoint is exceeded, the channel output relay actuates, which then outputs an RPS trip signal to the trip logic.

(continued)

BASES

BACKGROUND (continued)

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A and C, B and D), as shown in Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as one-out-of-two taken twice logic. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

Two scram pilot valves are located in the hydraulic control unit (HCU) for each control rod drive (CRD). Each scram pilot valve is solenoid operated, with the solenoids normally energized. The scram pilot valves control the air supply to the scram inlet and outlet valves for the associated CRD. When either scram pilot valve solenoid is energized, air pressure holds the scram valves closed and, therefore, both scram pilot valve solenoids must be de-energized to cause a control rod to scram. The scram valves control the supply and discharge paths for the CRD water during a scram. One of the scram pilot valve solenoids for each CRD is controlled by trip system A, and the other solenoid is controlled by trip system B. Any trip of trip system A in conjunction with any trip in trip system B results in de-energizing both solenoids, air bleeding off, scram valves opening, and control rod scram.

The backup scram valves, which energize on a scram signal to depressurize the scram air header, are also controlled by the RPS. Additionally, the RPS System controls the SDV vent and drain valves such that when both trip systems trip, the SDV vent and drain valves close to isolate the SDV.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 2, 3, and 4. The RPS initiates a reactor scram when monitored parameter values exceed the Allowable Values specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), and the containment by minimizing the energy that must be absorbed following a LOCA.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

RPS instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Functions not specifically credited in the accident analysis are retained for the RPS as required by the NRC approved licensing basis.

The OPERABILITY of the RPS is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.1.1-1. Each Function must have a required number of OPERABLE channels per RPS trip system, with their setpoints within the specified Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time.

Allowable Values are specified for each RPS Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of scram pilot valves and associated solenoids, backup scram valves, and SDV valves, described in the Background section, are not addressed by this LCO.

The individual Functions are required to be OPERABLE in the MODES specified in the Table that may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions is required in each MODE to provide primary and diverse initiation signals.

RPS is required to be OPERABLE in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. Control rods withdrawn from a core cell containing no fuel assemblies do not affect the reactivity of the core and therefore are not required to have the capability to scram. Provided all other control rods remain inserted, the RPS function is not required. In this condition, the required SDM (LCO 3.1.1, "Shutdown Margin (SDM)") and refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") ensure that no event requiring RPS will occur. During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode Switch—Shutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. Under these conditions, the RPS function is not required to be OPERABLE.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1.a. Intermediate Range Monitor (IRM) Neutron Flux-High

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection for the rod pattern controller (RPC), which monitors and controls

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Intermediate Range Monitor (IRM) Neutron Flux-High (continued)

the movement of control rods at low power. The RPC prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 5). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, generic analyses have been performed (Ref. 6) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel energy depositions below the 170 cal/gm fuel failure threshold criterion.

The IRMs are also capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed.

The IRM System is divided into two groups of IRM channels, with four IRM channels inputting to each trip system. The analysis of Reference 6 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This trip is active in each of the 10 ranges of the IRM, which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The analysis of Reference 6 has adequate conservatism to permit an IRM Allowable Value of 122 divisions of a 125 division scale.

The Intermediate Range Monitor Neutron Flux—High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a core cell containing one or more fuel assemblies has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System, the rod withdrawal limiter (RWL), and the RPC provide protection against control rod withdrawal error events and the IRMs are not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Intermediate Range Monitor-Inop

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or a module is not plugged in, an inoperative trip signal will be received by the RPS unless the IRM is bypassed. Since only one IRM in each trip system may be bypassed, only one IRM in each RPS trip system may be inoperable without resulting in an RPS trip signal.

This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

Six channels of Intermediate Range Monitor – Inop with three channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

Since this Function is not assumed in the safety analysis, there is no Allowable Value for this Function.

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux – High Function is required.

2.a. Average Power Range Monitor Neutron Flux-High, Setdown

The APRM channels receive input signals from the local power range monitors (LPRM) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux – High, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux – High, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux – High Function because of the relative setpoints.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High, Setdown (continued)

With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux–High, Setdown Function will provide the primary trip signal for a corewide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux–High, Setdown Function. However, this Function indirectly ensures that, before the reactor mode switch is placed in the run position, reactor power does not exceed 23.8% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 23.8% RTP.

The APRM System is divided into two groups of channels with four APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Six channels of Average Power Range Monitor Neutron Flux–High, Setdown, with three channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 23.8% RTP.

The Average Power Range Monitor Neutron Flux–High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists. In MODE 1, the Average Power Range Monitor Neutron Flux–High Function provides protection against reactivity transients and the RWL and RPC protect against control rod withdrawal error events.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power-High

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux-High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux-High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function setpoint is exceeded.

During continued operation with only one recirculation loop in service, the APRM flow biased simulated thermal power-high setpoint is required to be conservatively set (refer to the Bases for LCO 3.4.1, "Recirculation Loops Operating," for more detailed discussion). The setpoint modification may be delayed for up to 24 hours in accordance with the allowances of LCO 3.4.1. After this time, the LCO 3.3.1.1 requirement for APRM OPERABILITY will enforce the more conservative setpoint.

The APRM System is divided into two groups of channels with four APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one Average Power Range Monitor channel in a trip system can cause the associated trip system to trip.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power-High (continued)

Six channels of Average Power Range Monitor Flow Biased Simulated Thermal Power—High, with three channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM channel receives one total drive flow signal representative of total core flow. The recirculation loop drive flow signals are generated by eight flow units. One flow unit from each recirculation loop is provided to each APRM channel. Total drive flow is determined by each APRM by summing up the flow signals provided to the APRM from the two recirculation loops.

The clamped Allowable Value function was not specifically credited in the accident analysis, but it is retained for RPS as required by the NRC approved licensing basis. The THERMAL POWER time constant provided in the CORE OPERATING LIMITS REPORT is representative of the fuel heat transfer dynamics and provides a signal that is proportional to the THERMAL POWER.

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

2.c. Average Power Range Monitor Fixed Neutron Flux—High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux-High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 2, the Average Power Range Monitor Fixed Neutron Flux—High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Average Power Range Monitor Fixed Neutron Flux-High (continued)

pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 7) takes credit for the Average Power Range Monitor Fixed Neutron Flux-High Function to terminate the CRDA.

The APRM System is divided into two groups of channels with four APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Six channels of Average Power Range Monitor Fixed Neutron Flux-High with three channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 14 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux-High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux-High Function is assumed in the CRDA analysis that is applicable in MODE 2, the Average Power Range Monitor Neutron Flux-High, Setdown Function conservatively bounds the assumed trip and, together with the IRM trips, provides adequate protection. Therefore, the Average Power Monitor Fixed Neutron Flux-High Function is not required in MODE 2.

2.d. Average Power Range Monitor-Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than Operate, an APRM module is unplugged, the electronic operating voltage is high or low, the flow channel switch is not in the operate position, the flow card is out of file, or the APRM has too few LPRM inputs (<14), an inoperative trip signal will be

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor-Inop (continued)

received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for RPS as required by the NRC approved licensing basis.

Six channels of Average Power Range Monitor—Inop with three channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

3. Reactor Vessel Steam Dome Pressure-High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure—High Function initiates a scram for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 2, the reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux—High signal, not the Reactor Vessel Steam Dome Pressure—High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure—High Allowable Value is

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Reactor Vessel Steam Dome Pressure-High (continued)

chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure-High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level-Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at Level 3 to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level-Low, Level 3 Function is assumed in the analysis of the DBA LOCA (Ref. 3). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level-Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level-Low, Level 3 Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level-Low, Level 3 Allowable Value is selected to ensure that, for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS at RPV Water Level 1 will not be required.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Reactor Vessel Water Level-Low, Level 3 (continued)

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor Vessel Water Level-Low Low, Level 2 and Low Low Low, Level 1 provide sufficient protection for level transients in all other MODES.

An operating bypass of the reactor vessel low water level trip is provided with the EOP keylock switches in the 'BYPASS' position and the mode switch in the 'SHUTDOWN' (MODE 3) position. The interlock with the mode switch will ensure that the reactor is in the shutdown condition prior to bypassing the reactor water level 3 scram.

5. Reactor Vessel Water Level-High, Level 8

High RPV water level indicates a potential problem with the feedwater level control system, resulting in the addition of reactivity associated with the introduction of a significant amount of relatively cold feedwater. Therefore, a scram is initiated at Level 8 to ensure that MCPR is maintained above the MCPR SL. The Reactor Vessel Water Level-High, Level 8 Function is one of the many Functions assumed to be OPERABLE and capable of providing a reactor scram during transients analyzed in Reference 3. It is directly assumed in the analysis of feedwater controller failure, maximum demand (Ref. 4).

Reactor Vessel Water Level-High, Level 8 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level-High, Level 8 Allowable Value is specified to ensure that the MCPR SL is not violated during the assumed transient.

Four channels of the Reactor Vessel Water Level-High, Level 8 Function, with two channels in each trip system arranged in a one-out-of-two logic, are available and are required to be OPERABLE when THERMAL POWER is ≥ 23.8% RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 23.8% RTP, this Function is not required since MCPR is not a concern below 23.8% RTP.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Main Steam Isolation Valve-Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the Nuclear Steam Supply System and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve – Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 2, the Average Power Range Monitor Fixed Neutron Flux – High Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in Reference 4 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below limits of 10 CFR 50.46. The reactor scram resulting from an MSIV closure due to a Low Main Steam Line Pressure Isolation also ensures reactor power is less than 23.8% RTP before reactor pressure decreases below the Safety Limit 2.1.1 Low Pressure Limit of 686 psig.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. Each MSIV has two position switches: one inputs to RPS trip system A while the other inputs to RPS trip system B. Thus, each RPS trip system receives an input from eight Main Steam Isolation Valve – Closure Function channels, each consisting of one position switch. The logic for the Main Steam Isolation Valve – Closure Function is arranged such that either the inboard or outboard valve on three or more of the main steam lines (MSLs) must close in order for a scram to occur.

The Main Steam Isolation Valve – Closure Allowable Value is specified to ensure that a scram occurs prior to a significant reduction in steam flow, thereby reducing the severity of the subsequent pressure transient.

Sixteen channels of the Main Steam Isolation Valve – Closure Function with eight channels in each trip system are required to be OPERABLE to ensure that no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 since, with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Main Steam Isolation Valve-Closure (continued)

close. In MODE 2, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection.

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the RCPB. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the drywell. The Drywell Pressure-High Function is assumed in the analysis of a DBA LOCA (Ref. 3).

High drywell pressure signals are initiated from four pressure transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

Four channels of Drywell Pressure-High Function, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

8.a, b. Scram Discharge Volume Water Level-High

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated when the remaining free volume is still sufficient to accommodate the water from a full core scram. However, even though the two types of Scram Discharge Volume Water Level-High Functions are an input to the RPS logic, no credit is taken for a scram initiated from these Functions for any of the design basis

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8.a, b. Scram Discharge Volume Water Level - High (continued)

accidents or transients analyzed in the USAR. However, they are retained to ensure that the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two transmitters and trip units for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a transmitter and trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 8.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level - High Function, with two channels of each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

9. Turbine Stop Valve Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Stop Valve Closure (continued)

Turbine Stop Valve Closure signals are initiated by limit switches at each stop valve. Two independent limit switches are associated with each stop valve. One of the two limit switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve Closure channels, each consisting of one limit switch. The logic for the Turbine Stop Valve Closure Function is such that three or more TSVs must be closed to produce a scram.

The Turbine Stop Valve Closure Allowable Value is selected to be high enough to detect imminent TSV closure thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve Closure, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close.

This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is $\geq$ 38% RTP. This Function is not required when THERMAL POWER is < 38% RTP since the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor Fixed Neutron Flux-High Functions are adequate to maintain the necessary safety margins. Enabling of this Function is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function. The setpoint is feedwater temperature dependent as a result of the subcooling changes that affect the turbine first stage pressure/reactor power relationship.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure-Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure switch associated with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER $\geq$ 38% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure; opening of the turbine bypass valves may affect this Function.

The Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of the Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is $\geq$ 38% RTP. This Function is not required when THERMAL POWER is $<$ 38% RTP since the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor Fixed Neutron Flux-High Functions are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Reactor Mode Switch - Shutdown Position

The Reactor Mode Switch - Shutdown Position Function provides signals, via the manual scram logic channels, that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with four channels, each of which inputs into one of the RPS logic channels.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

Four channels of Reactor Mode Switch - Shutdown Position Function, with two channels in each trip system, are available and required to be OPERABLE. The Reactor Mode - Switch Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

12. Manual Scram

The Manual Scram push button channels provide signals, via the manual scram logic channels, to each of the four RPS logic channels that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the four RPS logic channels. In order to cause a scram it is necessary that at least one channel in each trip system be actuated.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

12. Manual Scram (continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic, are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate, inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 9) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases.) If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped

(continued)

ACTIONS

A.1 and A.2 (continued)

condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic for any Function would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 9 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference 9, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels, if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision as to which trip system is in the more degraded state should be based on prudent judgment and current plant

(continued)

ACTIONS

B.1 and B.2 (continued)

conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram or EOC-RPT), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 6 (Main Steam Isolation Valve—Closure), this would require both trip systems to have each channel associated with the MSIVs in three MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip). For Function 9 (Turbine Stop Valve Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

(continued)

BASES

ACTIONS

C.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C, and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, G.1, and H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)." The power reduction required by Required Action E.1 shall be initiated within 15 minutes. The THERMAL POWER referred to is that corresponding to the turbine first stage pressure at which the automatic bypass of the reactor scram on closure of the turbine stop or control valves occurs.

I.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core

(continued)

ACTIONS

I.1 (continued)

cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Additionally, for Function 12, Manual Scram, the mode switch shall be locked in the shutdown position.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that, when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the RPS reliability analysis (Ref. 9) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

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 instrument channels could be an indication of excessive instrument drift on one of the channels or 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 3.3.1.1.1 (continued)

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to the reactor power calculated from a heat balance if the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP. If the heat balance calculated reactor power exceeds the APRM channel output by more than 2% RTP, the APRM is not declared inoperable, but must be adjusted consistent with the heat balance calculated power. If the APRM channel output cannot be properly adjusted, the channel is declared inoperable.

This Surveillance does not preclude making APRM channel adjustments, if desired, when the heat balance calculated reactor power is less than the APRM channel output. To provide close agreement between the APRM indicated power and to preserve operating margin, the APRM channels are normally adjusted to within +/-2% of the heat balance calculated reactor power. However, this agreement is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

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

A restriction to satisfying this SR when < 23.8% RTP is provided that requires the SR to be met only at ≥ 23.8% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 23.8% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large inherent margin to thermal limits (MCPR and APLHGR). At ≥ 23.8% RTP, the Surveillance is required to have been satisfactorily performed in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 23.8% if the Frequency is not met per

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.2 (continued)

SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 23.8% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function uses the recirculation loop drive flows to vary the trip setpoint. This SR ensures that the total loop drive flow signals from the flow unit used to vary the setpoint are appropriately compared to a calibrated flow signal and therefore the APRM Function accurately reflects the required setpoint as a function of flow. Each flow signal from the respective flow unit must be $\leq$ 105% of the calibrated flow signal. If the flow unit signal is not within the limit, the APRMs that receive an input from the inoperable flow unit must be declared inoperable.

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

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.6 and SR 3.3.1.1.7

These Surveillances are established to ensure that no gaps in neutron flux indication exist from subcritical to power operation for monitoring core reactivity status.

The overlap between SRMs and IRMs is required to be demonstrated to ensure that reactor power will not be increased into a region without adequate neutron flux indication. This is required prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs.

The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (initiate a rod block) if adequate overlap is not maintained.

Overlap (nominally 1/2 decade) between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap (nominally 1/2 decade) between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above 10/125 on range 1 before SRMs have reached the upscale rod block.

As noted, SR 3.3.1.1.7 is only required to be met during entry into MODE 2 from MODE 1. That is, after the overlap requirement has been met and indication has transitioned to the IRMs, maintaining overlap is not required (APRMs may be reading downscale once in MODE 2).

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channel(s) that are required in the current MODE or condition should be declared inoperable.

The Surveillance Frequency of SR 3.3.1.1.7 is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.10

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.17

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the calorimetric calibration (SR 3.3.1.1.2) and the LPRM calibration against the TIPs (SR 3.3.1.1.8). As also noted the flow reference transmitters are not calibrated in SR 3.3.1.1.11, but have a separate Surveillance (SR 3.3.1.1.17). A second note is provided in SR 3.3.1.1.11 and SR 3.3.1.1.13 that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

The Average Power Range Monitor Flow Biased Simulated Thermal Power-High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The filter time constant is specified in the COLR and must be verified to ensure that the channel is accurately reflecting the desired parameter.

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

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic upon the receipt of either actual or simulated automatic trip signals. The functional testing of control rods, in LCO 3.1.3, “Control Rod OPERABILITY,” and SDV vent and drain valves, in LCO 3.1.8, “Scram Discharge Volume (SDV) Vent and Drain Valves,” overlaps this Surveillance to provide complete testing of the assumed safety function.

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

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 38% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during the calibration at THERMAL POWER ≥ 38% RTP to ensure that the calibration remains valid.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16 (continued)

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 38% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition (Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are enabled), this SR is met and the channel is considered OPERABLE.

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

SR 3.3.1.1.18

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in Reference 10.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. In addition, for Functions 3, 4 and 5, the associated sensors are not required to be response time tested. For these Functions, response time testing for the remaining channel components is required. This allowance is supported by Reference 11.

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

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SR 3.3.1.1.19

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Figure 7.2-1.
2. USAR, Section 5.2.2.
3. USAR, Section 6.3.3.
4. USAR, Chapter 15.
5. USAR, Section 15.4.1.
6. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
7. USAR, Section 15.4.9.
8. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980, as attached to NRC Generic Letter dated December 9, 1980.
9. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
10. GE DSDS 22A3771AJ.
11. NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994.

B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

The SRMs provide the operator with information relative to the neutron level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and to determine when criticality is achieved. The SRMs are maintained fully inserted until the count rate is greater than a minimum allowed count rate (a control rod block is set at this condition). After SRM to intermediate range monitor (IRM) overlap is demonstrated (as required by SR 3.3.1.1.6), the SRMs are normally fully withdrawn from the core.

The SRM subsystem of the Neutron Monitoring System (NMS) consists of four channels. Each of the SRM channels can be bypassed, but only one at any given time, by the operation of a bypass switch. Each channel includes one detector that can be physically positioned in the core. Each detector assembly consists of a miniature fission chamber with associated cabling, signal conditioning equipment, and electronics associated with the various SRM functions. The signal conditioning equipment converts the current pulses from the fission chamber to analog DC currents that correspond to the count rate. Each channel also includes indication, alarm, and control rod blocks. However, this LCO specifies OPERABILITY requirements only for the monitoring and indication functions of the SRMs.

During refueling, shutdown, and low power operations, the primary indication of neutron flux levels is provided by the SRMs or special movable detectors connected to the normal SRM circuits. The SRMs provide monitoring of reactivity changes during fuel or control rod movement and give the control room operator early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation are provided by LCO 3.9.1, "Refueling Equipment Interlocks"; LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"; LCO 3.3.1.1, "Reactor Protection

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	System (RPS) Instrumentation," Intermediate Range Monitor (IRM) Neutron Flux High and Average Power Range Monitor (APRM) Neutron Flux—High, Setdown Functions; and LCO 3.3.2.1, "Control Rod Block Instrumentation." The SRMs have no safety function and are not assumed to function during any design basis accident or transient analysis. However, the SRMs provide the only on scale monitoring of neutron flux levels during startup and refueling. Therefore, they are being retained in the Technical Specifications.
LCO	During startup in MODE 2, three of the four SRM channels are required to be OPERABLE to monitor the reactor flux level prior to and during control rod withdrawal, to monitor subcritical multiplication and reactor criticality, and to monitor neutron flux level and reactor period until the flux level is sufficient to maintain the IRM on Range 3 or above. All channels but one are required in order to provide a representation of the overall core response during those periods when reactivity changes are occurring throughout the core. In MODES 3 and 4, with the reactor shut down, two SRM channels provide redundant monitoring of flux levels in the core. In MODE 5, during a spiral offload or reload, an SRM outside the fueled region will no longer be required to be OPERABLE, since it is not capable of monitoring neutron flux in the fueled region of the core. Thus, CORE ALTERATIONS are allowed in a quadrant with no OPERABLE SRM in an adjacent quadrant, as provided in the Table 3.3.1.2-1, footnote (b), requirement that the bundles being spiral reloaded or spiral offloaded are all in a single fueled region containing at least one OPERABLE SRM is met. Spiral reloading and offloading encompass reloading or offloading a cell on the edges of a continuous fueled region (the cell can be reloaded or offloaded in any sequence).

(continued)

BASES

LCO (continued)

In nonspiral routine operations, two SRMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate coverage is provided by requiring one SRM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed and the other SRM to be OPERABLE in an adjacent quadrant containing fuel. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS.

Special movable detectors, according to Table 3.3.1.2-1, footnote (c), may be used during CORE ALTERATIONS in place of the normal SRM nuclear detectors. These special detectors must be connected to the normal SRM circuits in the NMS such that the applicable neutron flux indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2, and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication. To do this, the SRM must be inserted to the normal operating level and there must be continuous visual indication in the control room.

APPLICABILITY

The SRMs are required to be OPERABLE in MODES 2, 3, 4, and 5, prior to the IRMs being on scale on Range 3 to provide for neutron monitoring. In MODE 1, the APRMs provide adequate monitoring of reactivity changes in the core; therefore, the SRMs are not required. In MODE 2, with IRMs on Range 3 or above, the IRMs provide adequate monitoring and the SRMs are not required.

ACTIONS

A.1 and B.1

In MODE 2, with the IRMs on Range 2 or below, SRMs provide the means of monitoring core reactivity and criticality. With any number of the required SRMs inoperable, the ability to monitor is degraded. Therefore, a limited time is allowed to restore the inoperable channels to OPERABLE status.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

Providing that at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This is a reasonable time since there is adequate capability remaining to monitor the core, limited risk of an event during this time, and sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase are not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater (with overlap required by SR 3.3.1.1.6) and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

With three required SRMs inoperable, Required Action B.1 allows no positive changes in reactivity (control rod withdrawal must be immediately suspended) due to the inability to monitor the changes. Required Action A.1 still applies and allows 4 hours to restore monitoring capability prior to requiring control rod insertion. This allowance is based on the limited risk of an event during this time, provided that no control rod withdrawals are allowed, and the desire to concentrate efforts on repair, rather than to immediately shut down, with no SRMs OPERABLE.

C.1

In MODE 2, if the required number of SRMs is not restored to OPERABLE status within the allowed Completion Time, the reactor shall be placed in MODE 3. With all control rods fully inserted, the core is in its least reactive state with the most margin to criticality. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

D.1 and D.2

With one or more required SRM channels inoperable in MODE 3 or 4, the neutron flux monitoring capability is degraded or nonexistent. The requirement to fully insert all insertable

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

control rods ensures that the reactor will be at its minimum reactivity level while no neutron monitoring capability is available. Placing the reactor mode switch in the shutdown position prevents subsequent control rod withdrawal by maintaining a control rod block. The allowed Completion Time of 1 hour is sufficient to accomplish the Required Action, and takes into account the low probability of an event requiring the SRM occurring during this time. Although not a Technical Specification requirement, to ensure that the mode switch remains in the shutdown position, the mode switch should be locked.

E.1 and E.2

With one or more required SRMs inoperable in MODE 5, the capability to detect local reactivity changes in the core during refueling is degraded. CORE ALTERATIONS must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Suspending CORE ALTERATIONS prevents the two most probable causes of reactivity changes, fuel loading and control rod withdrawal, from occurring. Inserting all insertable control rods ensures that the reactor will be at its minimum reactivity, given that fuel is present in the core. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe, conservative position.

Action (once required to be initiated) to insert control rods must continue until all insertable rods in core cells containing one or more fuel assemblies are inserted.

SURVEILLANCE REQUIREMENTS

The SRs for each SRM Applicable MODE or other specified condition are found in the SRs column of Table 3.3.1.2-1.

SR 3.3.1.2.1 and SR 3.3.1.2.3

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 the same parameter indicated on other similar

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.1 and SR 3.3.1.2.3. (continued)

channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. During performance of the CHANNEL CHECK, the SRMs shall be verified to be inserted to the normal operating level. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. OPERABLE SRMs must be inserted to the normal operating level. Note 1 states that this SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE, per Table 3.3.1.2-1, footnote (b), only the

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.2 (continued)

a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate. This ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. Verification of the signal to noise ratio also ensures that the detectors are inserted to a normal operating level. In a fully withdrawn condition, the detectors are sufficiently removed from the fueled region of the core to essentially eliminate neutrons from reaching the detector. Any count rate obtained while fully withdrawn is assumed to be "noise" only. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met for an SRM that has less than or equal to four fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With four or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated quadrant, even with a control rod withdrawn the configuration will not be critical.

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.5

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Note to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hours is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

SR 3.3.1.2.6

Performance of a CHANNEL CALIBRATION verifies the performance of the SRM detectors and associated circuitry. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The neutron detectors are excluded from the CHANNEL CALIBRATION because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range, and with an accuracy specified for a fixed useful life.

The Note to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2.6 (continued)

inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hours is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.1.3 Oscillation Power Range Monitor (OPRM) Instrumentation

BASES

BACKGROUND

General Design Criterion 10 (GDC 10) requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. Additionally, GDC 12 requires the reactor core and associated coolant, control, and protection systems to be designed to assure that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The Oscillation Power Range Monitor (OPRM) System provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel minimum critical power ratio (MCPR) Safety Limit.

References 1, 2, and 3 describe three separate algorithms for detecting stability related oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. The OPRM System hardware implements these algorithms in microprocessor based modules. These modules execute the algorithms based on local power range monitor (LPRM) inputs, and generate alarms and trips based on these calculations. These trips result in tripping the Reactor Protection System (RPS) when the appropriate RPS trip logic is satisfied, as described in the Bases for LCO 3.3.1.1, "RPS Instrumentation." Only the period based detection algorithm is used in the safety analysis (Ref. 1, 2, 6, 7, and 17). Therefore, only the period based detection algorithm is required for channel OPERABILITY. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations.

(continued)

BASES

BACKGROUND (continued)

The period based detection algorithm detects a stability related oscillation based on the occurrence of a fixed number of consecutive LPRM signal period confirmations followed by the LPRM signal amplitude exceeding a specified setpoint. Upon detection of a stability related oscillation, a trip is generated for that OPRM channel. This period based detection algorithm amplitude and confirmation count setpoints are determined in accordance with Reference 17.

The OPRM System consists of 4 OPRM trip channels, each channel consisting of two OPRM modules. Each OPRM module receives input from LPRMs. Each OPRM module also receives input from the Neutron Monitoring System (NMS) average power range monitor (APRM) power and flow signals to automatically enable the trip function of the OPRM module in specific areas of the power to flow map.

Each OPRM module is continuously tested by a self-test function. On detection of any OPRM module failure, either a Trouble light or an INOP alarm are activated. Trouble indicates the OPRM module is still functioning but needs attention, while INOP indicates that the OPRM module may not be capable of meeting its functional requirements.

APPLICABLE SAFETY ANALYSIS

It has been shown that BWR cores may exhibit thermal-hydraulic reactor instabilities in high power and low flow portions of the core power to flow operating domain. GDC 10 requires the reactor core and associated coolant, control, and protection systems to be designed with appropriate margin to assure that acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. GDC 12 requires assurance that power oscillations which can result in conditions exceeding acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM System provides compliance with GDC 10 and GDC 12 by detecting the onset of oscillations and suppressing them by initiating a reactor scram. This assures that the MCPR safety limit will not be violated for anticipated oscillations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The OPRM Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Four channels of the OPRM period based detection algorithm are required to be OPERABLE to ensure that stability related oscillations are detected and suppressed prior to exceeding the MCPR safety limit. Only one of the two OPRM modules period based detection algorithm is required for OPRM channel OPERABILITY. The highly redundant and low minimum number of required LPRMs in the OPRM cell design ensures that large numbers of cells will remain OPERABLE, even with large numbers of LPRMs bypassed.
APPLICABILITY	The OPRM instrumentation is required to be OPERABLE in order to detect and suppress neutron flux oscillations in the event of thermal-hydraulic instability. As described in References 1, 2, and 3, the power/core flow region protected against anticipated oscillations is defined by THERMAL POWER $\geq$ 23.8% RTP and recirculation drive flow < the value corresponding to 60% of rated core flow. The OPRM trip is required to be enabled in this region, and the OPRM must be capable of enabling the trip function as a result of transients that place the core into that power/flow region. Therefore, the OPRM is required to be OPERABLE with THERMAL POWER $\geq$ 23.8% RTP, and at all core flows while above that THERMAL POWER. It is not necessary for the OPRM to be OPERABLE with THERMAL POWER < 23.8% RTP because instabilities would not be expected to grow large enough to threaten the MCPR Safety Limit. This expectation is due, in part, to the large MCPR margin that exists at low power (Ref. 6).

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to the OPRM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable OPRM instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable OPRM instrumentation channel.

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

Because of the reliability and on-line self-testing of the OPRM instrumentation and the redundancy of the RPS design, an allowable out of service time of 30 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the OPRM instrumentation still maintains OPRM trip capability (refer to Required Action B.1). The remaining OPERABLE OPRM channels continue to provide trip capability (see Condition B) and provide operator information relative to stability activity. The remaining OPRM modules have high reliability. With this high reliability, there is a low probability of a subsequent channel failure within the allowable out of service time. In addition, the OPRM modules continue to perform on-line self-testing and alert the operator if any further system degradation occurs.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the OPRM channel or associated RPS trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable OPRM channel in trip (or the associated RPS trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the OPRM channel (or RPS trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), the alternate method of detecting and suppressing thermal-hydraulic instability oscillations is required (Required Action A.3). This alternate method is described in Reference 5. It consists of increased operator awareness and monitoring for neutron flux oscillations when operating in the region where oscillations are possible. If indications of oscillation, as described in Reference 5, are observed by the operator, the operator will take the actions described by procedures, which include initiating a manual scram of the reactor.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped OPRM channels within the same RPS trip system result in not maintaining OPRM trip capability. The RPS logic is one-out-of-two taken twice. OPRM trip capability is considered to be maintained when sufficient OPRM channels are OPERABLE or in trip (or the associated RPS trip system is in trip), such that a valid OPRM signal will generate a trip signal in both RPS trip systems. This would require both RPS trip systems to have at least one OPRM channel OPERABLE or in trip (or the associated RPS trip system in trip).

(continued)

BASES

ACTIONS

B.1 (continued)

Because of the low probability of the occurrence of an instability, 12 hours is an acceptable time to initiate the alternate method of detecting and suppressing thermal-hydraulic instability oscillations as described in the Bases for Action A.3 above. The alternate method of detecting and suppressing thermal-hydraulic instability oscillations would adequately address detection and mitigation in the event of instability oscillations. Based on industry operating experience with actual instability oscillations, the operator would be able to recognize instabilities during this time and take action to suppress them through a manual scram. In addition, the OPRM System may still be available to provide alarms to the operator if the onset of oscillations were to occur. Since plant operation is minimized in areas where oscillations may occur, operation without OPRM trip capability is considered acceptable with implementation of the alternate method of detecting and suppressing thermal-hydraulic instability oscillations, during the period when corrective actions are underway to resolve the inoperability that led to entry into Condition B. One reason this Condition may be utilized is to provide time to implement a software upgrade in the plant if a common cause software problem is identified.

C.1

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 23.8% RTP within 4 hours. Reducing THERMAL POWER to < 23.8% RTP places the plant in a region where instabilities are not likely to occur. The 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER < 23.8% RTP from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

For the following OPRM instrumentation surveillances, both OPRM modules are tested, although only one is required to satisfy the surveillance requirement.

SR 3.3.1.3.1

A CHANNEL FUNCTIONAL TEST is performed to ensure that the channel will perform the intended function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.3.2

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the OPRM System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.3.3

The CHANNEL CALIBRATION verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations. Calibration of the channel provides a check of the internal reference voltage and the internal processor clock frequency. Since the OPRM is a digital system, the internal reference voltage and processor clock frequency are, in turn, used to automatically calibrate the internal analog to digital converters. The calibration also compares the desired trip setpoints with those in processor memory. The Allowable Values for the confirmation count setpoint (N_p) and the amplitude trip setpoint (S_p) are specified in the Core Operating Limits Report (COLR). As noted, neutron detectors are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3.3 (continued)

excluded from CHANNEL CALIBRATION because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the LPRM calibration using the TIPs (SR 3.3.1.3.2).

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

SR 3.3.1.3.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods in LCO 3.1.3, "Control Rod OPERABILITY," and scram discharge volume (SDV) vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function. The OPRM self-test function may be utilized to perform this testing for those components that it is designed to monitor.

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

SR 3.3.1.3.5

This SR ensures that trips initiated from the OPRM System will not be inadvertently bypassed when THERMAL POWER is 23.8% RTP and recirculation drive flow is < the value corresponding to 60% of rated core flow.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3.5 (continued)

This normally involves verification of the OPRM bypass function, by ensuring the OPRM modules are enabled when the APRM input is 23.8% RTP and the recirculation drive flow input is < the value corresponding to 60% of rated core flow. The APRM and recirculation drive flow inputs are calibrated by surveillances in their respective Technical Specifications. Because the enabled region conservatively bounds the region where instabilities are actually expected, the above nominal values of power/flow are utilized for the bypass setpoints, without further allowance for instrument drift or uncertainty.

If any bypass channel setpoint is nonconservative (i.e., the OPRM module is bypassed at 23.8% RTP and recirculation drive flow < the value corresponding to 60% of rated core flow), then the affected OPRM module is considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (enabled). If placed in the enabled condition, this SR is met and the module is considered OPERABLE.

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

SR 3.3.1.3.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis (Ref. 10). The OPRM self-test function may be utilized to perform this testing for those components it is designed to monitor. The LPRM amplifier cards inputting to the OPRM are excluded from the OPRM response time testing. The RPS RESPONSE TIME acceptance criteria are included in Reference 11.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3.6 (continued)

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. NEDO-31960-A, "BWR Owners Group Long-Term Stability Solutions Licensing Methodology," November 1995.

2. NEDO 31960-A, Supplement 1, "BWR Owners Group Long-Term Stability Solutions Licensing Methodology," November 1995.

3. NRC Letter, A. Thadani to L. A. England, ''Acceptance for Referencing of Topical Reports NEDO-31960 and NEDO-31960 Supplement 1, 'BWR Owners Group Long-Term Stability Solutions Licensing Methodology',''
July 12, 1993.

4. Generic Letter 94-02, "Long-Term Solutions and Upgrade of Interim Operating Recommendations for Thermal-Hydraulic Instabilities in Boiling Water Reactors," July 11, 1994.

5. USAR Section 15B.4.4 Thermal and Hydraulic Design.

6. NEDO-32465-A, "BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology and Reload Applications," August 1996.

7. CENPD-400-P-A, Rev 01, "Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)," May 1995.

(continued)

BASES

REFERENCES (continued)

8. NRC Letter, B. Boger to R. Pinelli, "Acceptance of Licensing Topical Report CENPD-400-P, 'Generic Topical Report for the ABB Option III Oscillation Power Range Monitor'," August 16, 1995.

9. Deleted.

10. GENE-A13-00381-14, "Licensing Basis Hot Bundle Oscillation Magnitude for Perry" (latest approved revision).

11. USAR Table 7.2-3 "Reactor Protection System Response Time Table".

12. BWROG-94078, "BWR Owner's Group Guidelines for Stability Interim Corrective Action," June 1994.

13. BWROG-02072, "Review of BWR Owner's Group Guidelines for Stability Interim Corrective Action," November 20, 2002.

14. OG 02-0119-260, GE to BWR Owner's Group Detect and Suppress II Committee, "Backup Stability Protection (BSP) for Inoperable Option III Solution," July 17, 2002.

15. Calculation FM-037, Latest Revision.

16. Calculation FM-012, Latest Revision.

17. NEDE-33766P-A, Revision 1, "GEH Simplified Stability Solution (GS3)," March 2015.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

Control rods provide the primary means for control of reactivity changes. Control rod block instrumentation includes channel sensors, logic circuitry, switches, and relays that are designed to ensure that specified fuel design limits are not exceeded for postulated transients and accidents. During high power operation, the rod withdrawal limiter (RWL) provides protection for control rod withdrawal error events. During low power operations, control rod blocks from the rod pattern controller (RPC) enforce specific control rod sequences designed to mitigate the consequences of the control rod drop accident (CRDA). During shutdown conditions, control rod blocks from the Reactor Mode Switch – Shutdown Position Function ensure that all control rods remain inserted to prevent inadvertent criticalities.

The purpose of the RWL is to limit control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RWL supplies a trip signal to the Rod Control and Information System (RCIS) to appropriately inhibit control rod withdrawal during power operation equal to or greater than the low power setpoint (LPSP). The RWL has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. The rod block logic circuitry in the RCIS is arranged as two redundant and separate logic circuits. These circuits are energized when control rod movement is allowed. The output of each logic circuit is coupled to a comparator by the use of isolation devices in the rod drive control cabinet. The two logic circuit signals are compared and rod blocks are applied when either circuit trip signal is present. Control rod withdrawal is permitted only when the two signals agree. Each rod block logic circuit receives control rod position indication from a separate channel of the Rod Position Information System, each with a set of reed switches for control rod position indication. Control rod position is the primary data input for the RWL. First stage turbine pressure is used to determine reactor power level, with an LPSP and a high power setpoint (HPSP) used to determine allowable control rod withdrawal distances. Below the LPSP, the RWL is automatically bypassed (Ref. 1).

(continued)

BASES

BACKGROUND (continued)

The purpose of the RPC is to ensure control rod patterns during startup are such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to 19.0% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. The RPC, in conjunction with the RCIS, will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the specified sequence. The rod block logic circuitry is the same as that described above. The RPC also uses the turbine first stage pressure to determine when reactor power is above the power at which the RPC is automatically bypassed (Ref. 1).

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This function prevents criticality resulting from inadvertent control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, with each providing inputs into a separate rod block circuit. A rod block in either circuit will provide a control rod block to all control rods.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Rod Withdrawal Limiter

The RWL is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 2. A statistical analysis of RWE events was performed to determine the MCPR response as a function of withdrawal distance and initial operating conditions. From these responses, the fuel thermal performance was determined as a function of RWL allowable control rod withdrawal distance and power level.

The RWL satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Two channels of the RWL are available and are required to be OPERABLE to ensure that no single instrument failure can preclude a rod block from this Function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Rod Withdrawal Limiter (continued)

Nominal trip set points are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drive, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The RWL is assumed to mitigate the consequences of an RWE event when operating > 33.3% RTP. Below this power level, the consequences of an RWE event will not exceed the MCPR, and therefore the RWL is not required to be OPERABLE (Ref. 3).

1.b. Rod Pattern Controller

The RPC enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in References 4, 5, and 7. The standard BPWS (Ref. 4) requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with BPWS are specified in LCO 3.1.6, "Control Rod Pattern."

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Rod Pattern Controller (continued)

When performing a shutdown of the plant, an optional BPWS control rod sequence (Refs. 1, 7, and 8) may be used provided that all withdrawn control rods have been confirmed to be coupled. The rods may be inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled. When using the Reference 7 control rod insertion process, the rod pattern controller may be bypassed as permitted by the Applicability Note for the Rod Pattern Controller in Table 3.3.2.1-1. No control rod withdrawals are permitted while using this process.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Rod Pattern Controller (continued)

The Rod Pattern Controller Function satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Since the RPC is a backup to operator control of control rod sequences, only a single channel would be required to be OPERABLE to satisfy Criterion 3 (Ref. 5). However, the RPC is designed as a dual channel system and will not function without two OPERABLE channels. Required Actions of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing individual control rods in the Rod Action Control System (RACS) to allow continued operation with inoperable control rods or to allow correction of a control rod pattern not in compliance with the BPWS. The individual control rods may be bypassed as required by the conditions, and the RPC is not considered inoperable provided SR 3.3.2.1.9 is met.

Compliance with the BPWS, and therefore OPERABILITY of the RPC, is required in MODES 1 and 2 with THERMAL POWER ≤ 19.0% RTP. When THERMAL POWER is > 19.0% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA. In MODES 3 and 4, all control rods are required to be inserted in the core. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

2. Reactor Mode Switch-Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is required to be in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch-Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch-Shutdown Position Function satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Reactor Mode Switch – Shutdown Position (continued)

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. No Allowable Value is applicable for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5) no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5, with the reactor mode switch in the refueling position, the required position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") provides the required control rod withdrawal blocks.

ACTIONS

A.1

If either RWL channel is inoperable, the RWL may not be capable of performing its intended function. In most cases, with an inoperable channel, the RWL will initiate a control rod withdrawal block because the two channels will not agree. To ensure erroneous control rod withdrawal does not occur, however, Required Action A.1 requires that further control rod withdrawal be suspended immediately.

The rod withdrawal limiter is considered inoperable whenever the main turbine bypass valves are not fully closed and THERMAL POWER is greater than the low power setpoint. Control rod withdrawal shall be prevented in the above conditions and verified by a second licensed operator or other technically qualified member of the unit staff.

B.1

If either RPC channel is inoperable, the RPC may not be capable of performing its intended function even though, in most cases, all control rod movement will be blocked. All control rod movement should be suspended under these conditions until the RPC is restored to OPERABLE status.

(continued)

BASES

ACTIONS

B.1 (continued)

This action does not preclude a reactor scram. The RPC is not considered inoperable if individual control rods are bypassed in the RACS as required by LCO 3.1.3 or LCO 3.1.6. Under these conditions, continued operation is allowed if the bypassing of control rods and movement of control rods is verified by a second licensed operator or other qualified member of the technical staff per SR 3.3.2.1.9.

C.1 and C.2

If one Reactor Mode Switch – Shutdown Position control rod withdrawal block channel is inoperable, the remaining OPERABLE channel is adequate to perform the control rod withdrawal block function. Required Action C.1 and Required Action C.2 are consistent with the normal action of an OPERABLE Reactor Mode Switch – Shutdown Position Function to maintain all control rods inserted. Therefore, there is no distinction between Required Actions for the Conditions of one or two channels inoperable. In both cases (one or both channels inoperable), suspending all control rod withdrawal immediately, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies will ensure that the core is subcritical, with adequate SDM ensured by LCO 3.1.1, "SHUTDOWN MARGIN (SDM)." Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are therefore not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SR, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.1, SR 3.3.2.1.2, SR 3.3.2.1.3, and SR 3.3.2.1.4

The CHANNEL FUNCTIONAL TESTS for the RPC are performed by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying that a control rod block occurs. The CHANNEL FUNCTIONAL TESTS for the RWL are performed by selecting and attempting to move a restricted control rod in excess of the allowable distance. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. As noted, the SRs are not required to be performed until 1 hour after specified conditions are met (e.g., after any control rod is withdrawn in MODE 2). This allows entry into the appropriate conditions needed to perform the required SRs (e.g., during a power reduction for SR 3.3.2.1.4.) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.5

The LPSP is the point at which the RPCS makes the transition between the function of the RPC and the RWL. This transition point is automatically varied as a function of power. This power level is inferred from the first stage turbine pressure (one channel to each trip system). These power setpoints must be verified periodically to be within the Allowable Values. If any LPSP is nonconservative, then the affected Functions are considered inoperable. Since this channel has both upper and lower required limits, it is not allowed to be placed in a condition to enable either the RPC or RWL Function. Main Turbine bypass steam flow can affect LPSP nonconservatively for the RWL; therefore, opening the turbine bypass valve may affect the Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.6

This SR ensures the high power function of the RWL is not bypassed when power is above the HPSP. The power level is inferred from turbine first stage pressure signals. Periodic testing of the HPSP channels is required to verify the setpoint to be less than or equal to the limit. Adequate margins in accordance with setpoint methodologies are included. If the HPSP is nonconservative, then the RWL is considered inoperable. Alternatively, the HPSP can be placed in the conservative condition (nonbypass). If

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.6 (continued)

placed in the nonbypassed condition, the SR is met and the RWL would not be considered inoperable. Main Turbine bypass steam flow can affect LPSP nonconservatively for the RWL; therefore, opening the turbine bypass valve may affect the Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.1.7

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.2.1.8

The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch-Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links. This allows entry into MODES 3 and 4 if the Frequency is not met per SR 3.0.2.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.9

LCO 3.1.3 and LCO 3.1.6 may require individual control rods to be bypassed in RACS to allow insertion of an inoperable control rod or correction of a control rod pattern not in compliance with BPWS. To ensure the proper bypassing and movement of those affected control rods, a second licensed operator or other qualified member of the technical staff must verify the bypassing and movement of these control rods. No additional analyses are required for the bypassing and movement of these control rods, since these evolutions are adequately controlled by LCO 3.1.3 and LCO 3.1.6.

Individual control rods may also be required to be bypassed to allow continuous withdrawal for determining the location of leaking fuel assemblies, adjustment of control rod speed, or control rod scram time testing. To ensure the proper bypassing and movement of those affected control rods, a second licensed operator or other qualified member of the technical staff must verify the bypassing and movement of these control rods is in conformance with specific analyses for these evolutions.

With the control rods bypassed in the RACS, the RPC will not control the movement of these bypassed control rods. Compliance with this SR allows the RPC and RWL to be OPERABLE with these control rods bypassed.

REFERENCES

1. USAR, Section 7.6.1.5.
2. USAR, Section 15.4.2.
3. NEDE-24011-P-A-US, "General Electric Standard Application for Reload Fuel" (latest approved revision).
4. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.
5. NRC SER, Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.
6. Deleted.
7. NEDO-33091-A, Revision 2, ''Improved BPWS Control Rod Insertion Process,'' July 2004.
8. USAR 4.3.2.5.2.

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display plant 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 Events. The instruments that monitor these variables are designated as Type A, Category I, and non-Type A, Category I in accordance with Regulatory Guide 1.97 (Ref. 1).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident. This capability is consistent with the recommendations of Reference 1.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation LCO ensures the OPERABILITY of Regulatory Guide 1.97, Type A, variables so that the control room operating staff can:

- Perform the diagnosis specified in the Emergency Operating Procedures (EOPs). These variables are restricted to preplanned actions for the primary success path of Design Basis Accidents (DBAs) (e.g., loss of coolant accident (LOCA)); and
- Take the specified, preplanned, manually controlled actions for which no automatic control is provided, which are required for safety systems to accomplish their safety function.

The PAM instrumentation LCO also ensures OPERABILITY of Category I, non-Type A, variables. This ensures the control room operating staff can:

- Determine whether systems important to safety are performing their intended functions;

(continued)

APPLICABLE SAFETY ANALYSES (continued)

- Determine the potential for causing a gross breach of the barriers to radioactivity release;
- Determine whether a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to obtain an estimate of the magnitude of any impending threat.

The plant specific Regulatory Guide 1.97 analysis (Ref. 2) documents the process that identified Type A and Category I, non-Type A, variables.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Category I, non-Type A, instrumentation is retained in the Technical Specifications (TS) because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category I, non-Type A, variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires at least two OPERABLE channels for all but one Function to ensure no single failure prevents the operators from being presented with the information necessary to determine the status of the unit and to bring the unit to, and maintain it in, a safe condition following that accident.

Furthermore, provision of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exception to the two channel requirement is primary containment isolation valve (PCIV) position. In this case, the important information is the status of the primary containment penetrations. The LCO requires two position indicators for each penetration flow path. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the automatic valve and prior knowledge of passive valve or via system boundary status. If a normally automatic PCIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. In addition, Note (b) of Table 3.3.3.1-1 requires

(continued)

BASES

LCO (continued)

only one position indication for those penetrations which only have one position indication provided to the control room.

Listed below is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1, in the accompanying LCO.

1. Reactor Steam Dome Pressure

Reactor steam dome pressure is a Category I variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig monitor pressure. Wide range recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

2, 3. Reactor Vessel Water Level

Reactor vessel water level is a Category I variable provided to support monitoring of core cooling and to verify operation of the ECCS. The wide range and fuel zone water level channels provide the PAM Reactor Vessel Water Level Function. The wide range water level channels measure from 5 inches to 230 inches above the top of the active fuel. The fuel zone water level channels overlap with the wide range channels and measure from 50 inches above the top of the active fuel to 150 inches below the top of the active fuel. Both the wide range and the fuel zone water levels are measured by three independent differential pressure transmitters. The output from the three wide range water level channels are recorded on three independent pen recorders. The output of one fuel zone water level channel is recorded on a pen recorder. The two remaining channels provide meter indication only. However, two reactor vessel water level signals provide sufficient information to perform the above functions, and therefore only two are required to be OPERABLE for each function. These recorders and meter indications are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

(continued)

LCO

2, 3. Reactor Vessel Water Level (continued)

The wide range water level instruments are uncompensated for variation in reactor water density and are calibrated to be most accurate at operational pressure and temperature.

4. Suppression Pool Water Level

Suppression pool water level is a Category I variable provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. The wide range suppression pool water level measurement provides the operator with sufficient information to assess the status of the RCPB and to assess the status of the water supply to the ECCS. The wide range water level indicators monitor the suppression pool level from the center line of the ECCS suction lines to the top of the pool. Two wide range suppression pool water level signals are transmitted from separate differential pressure transmitters and are continuously recorded on two recorders in the control room. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5. Suppression Pool Sector Water Temperature

Suppression pool sector water temperature is a Category I variable provided to detect a condition that could potentially lead to containment breach, and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature instrumentation allows operators to detect trends in suppression pool water temperature in sufficient time to take action to prevent steam quenching vibrations in the suppression pool. Sixteen temperature sensors are arranged in eight groups of two independent and redundant channels.

Thus, eight groups of sensors are sufficient to monitor each relief valve discharge location. The outputs for the PAM sensors are recorded on two independent recorders in the control room. Both recorders must be OPERABLE to furnish two channels of PAM indication for each of the relief valve discharge locations. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

(continued)

BASES

LCO
(continued)

6. Drywell Pressure

Drywell pressure is a Category I variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Two wide range drywell pressure signals are transmitted from separate pressure transmitters and are continuously recorded and displayed on two control room recorders. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

7. Drywell Air Temperature

Drywell air temperature is a Category I variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Six wide range drywell air temperature signals are transmitted from separate temperature elements and are continuously recorded and displayed on two control room recorders. However, two drywell air temperature signals provide sufficient information to perform the above functions, and therefore only two are required to be OPERABLE. The recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

8. Primary Containment/Drywell Area Gross Gamma Radiation Monitors

Primary containment and drywell area gross gamma radiation is a Category I 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.

Primary containment area gross gamma radiation PAM instrumentation consists of two high range containment area radiation signals transmitted from separate radiation detectors and continuously recorded and displayed on two control room recorders. The recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

(continued)

BASES

LCO

8. Primary Containment/Drywell Area Gross Gamma Radiation Monitors (continued)

Drywell area gross gamma radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

The drywell area gross gamma radiation PAM instrumentation consists of two high range drywell area radiation signals transmitted from separate radiation detectors and continuously recorded and displayed on two control room recorders. The recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

9. Penetration Flow Path, Primary Containment Isolation Valve (PCIV) Position

PCIV position is provided for verification of containment integrity. In the case of PCIV position, the important information is the status of the containment penetration flow path. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each automatic PCIV in a containment penetration flow path; i.e., two total channels of PCIV position indication for a penetration flow path with two automatic valves. A channel consists of either the open limit switch or closed limit switch for each PCIV. For containment penetrations with only one automatic PCIV having control room indication, Note (b) requires a single channel of valve position indication to be OPERABLE. This is sufficient to verify redundantly the isolation status of each isolable penetration via indicated status of the automatic valve and, as applicable, prior knowledge of passive valve or system boundary status. If a 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, position indication for the PCIV(s) in the associated

(continued)

BASES

LCO

9. Penetration Flow Path, Primary Containment Isolation Valve (PCIV) Position (continued)

penetration flow path is not needed to determine status. Therefore, the position indication for valves in an isolated penetration is not required to be OPERABLE.

10. Deleted.

11. Primary Containment Pressure

Primary containment pressure is a Category I variable provided to verify RCS and containment integrity and to verify the effectiveness of ECCS actions taken to prevent containment breach. Two wide range primary containment pressure signals are transmitted from separate pressure transmitters and are continuously recorded and displayed on two control room recorders. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

(continued)

BASES

LCO (continued)

12. Primary Containment Air Temperature

Containment air temperature is a Category I variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Eight wide range primary containment air temperature signals (four per channel) are transmitted from separate temperature elements and are continuously recorded and displayed on two control room recorders. However, two primary containment air temperature signals provide sufficient information to perform the above functions, and therefore only two in each Function are required to be OPERABLE. The recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial

(continued)

BASES

ACTIONS (continued)

entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate inoperable functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel(s) (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), 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.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of actions to prepare and submit a special report to the NRC. This report discusses the cause of the inoperability and identifies proposed restorative actions. This report shall be submitted in accordance with 10 CFR 50.4 within 14 days of entering Conditions B. 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 plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required

(continued)

ACTIONS

C.1 (continued)

information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

This Required Action directs entry into the appropriate Condition referenced in Table 3.3.3.1-1. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1

For the majority of Functions in Table 3.3.3.1-1, if any Required Action and associated Completion Time of Condition C is not met, the plant must be placed in a MODE in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring primary containment and drywell area radiation have been developed and tested, the Required Action is not to shut down the plant but rather to initiate actions to prepare and submit a special report to the NRC. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the

(continued)

ACTIONS

F.1 (continued)

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 in which they are not equivalent, and provide a schedule for restoring the normal PAM channels. The special report shall be submitted in accordance with 10 CFR 50.4 within 14 days of entering Condition F.

SURVEILLANCE REQUIREMENTS

The following SRs apply to each PAM instrumentation Function in Table 3.3.3.1-1, except as noted below.

SR 3.3.3.1.1

For all Functions, 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 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 the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The Primary Containment and Drywell Gross Gamma Radiation Monitors should be compared to similar plant instruments located throughout the plant.

Agreement criteria are determined by the plant 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of those displays associated with the required channels of this LCO.

SR 3.3.3.1.2

Deleted.

SR 3.3.3.1.3

CHANNEL CALIBRATION is a complete check of the instrument loop including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The CHANNEL CALIBRATION for the Penetration Flow Path, PCIV Position consists of the Position Indictor Test (PIT), which is conducted in accordance with the INSERVICE TESTING PROGRAM. The CHANNEL CABLIBRATION for primary Containment/Drywell Area Gross Gamma Radiation Monitors shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.97, “Instrumentation for Light-Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident,” Revision 2, December 1980.

2. USAR, Table 7.1-4.

B 3.3 INSTRUMENTATION

B 3.3.3.2 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the Reactor Core Isolation Cooling (RCIC) System, the safety/relief valves, and the Residual Heat Removal Shutdown Cooling System can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the RCIC and the ability to operate shutdown cooling from outside the control room allow extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the plant 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 plant automatically reaches MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the Remote Shutdown System instrumentation and control Functions ensures that there is sufficient information available on selected plant parameters to place and maintain the plant 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 design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3.

(continued)

APPLICABLE SAFETY ANALYSES (continued)	The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1). The Remote Shutdown System is considered an important contributor to reducing the risk of accidents; as such, it has been retained in the Technical Specifications (TS) as indicated in the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in applicable plant instructions. The controls, instrumentation, and transfer switches are those required for: • Reactor pressure vessel (RPV) pressure control; • Decay heat removal; • RPV inventory control; and • Safety support systems for the above functions, including emergency service water, component cooling water, and onsite power, including the diesel generators. The Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown function are OPERABLE. In some cases the required information or control capability may be available from several alternate sources. In these cases, the Remote Shutdown System is OPERABLE as long as one channel of any of the alternate information or control sources for each Function is OPERABLE. The Remote Shutdown System instruments and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instruments and control circuits will be OPERABLE if plant 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 and 2. This is required so that the plant 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 MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore necessary instrumentation or control Functions if control room instruments or controls become unavailable. Consequently, the TS do not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

A Note has been provided to modify the ACTIONS related to Remote Shutdown System Functions. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable Remote Shutdown System Functions provide appropriate compensatory measures for separate Functions.

As such, a Note has been provided that allows separate Condition entry for each inoperable Remote Shutdown System Function.

<u>A.1</u>

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System is inoperable. This includes the control and transfer switches for any required Function.

(continued)

ACTIONS

A.1 (continued)

The Required Action is to restore the Function (both divisions, if applicable) to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

If the Required Action and associated Completion Time of Condition A 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 12 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2.2

SR 3.3.3.2.2 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 can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. However, this Surveillance is not required to be performed only during a plant outage. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies the channel responds to measured parameter values with the necessary range and accuracy. Valve position Functions are excluded since channel performance is adequately determined during performance of other valve Surveillances.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

B 3.3 INSTRUMENTATION

B 3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

BASES

BACKGROUND

The EOC-RPT instrumentation initiates a recirculation pump trip (RPT) to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to core thermal MCPR Safety Limits (SLs).

The need for the additional negative reactivity in excess of that normally inserted on a scram reflects end of cycle reactivity considerations. Flux shapes at the end of cycle are such that the control rods may not be able to ensure that thermal limits are maintained by inserting sufficient negative reactivity during the first few feet of rod travel upon a scram caused by Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure – Low, or Turbine Stop Valve (TSV) Closure. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity at a faster rate than the control rods can add negative reactivity.

The EOC-RPT instrumentation as discussed in Reference 1 is comprised of sensors that detect initiation of closure of the TSVs, or fast closure of the TCVs, combined with relays, logic circuits, and fast acting circuit breakers that interrupt the fast speed power supply to each of the recirculation pump motors. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an EOC-RPT signal to the trip logic. When the EOC-RPT breakers trip open, the recirculation pumps downshift to slow speed. The EOC-RPT has two identical trip systems, either of which can actuate an RPT.

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TSV Closure or two TCV Fast Closure, Trip Oil Pressure – Low signals are required for a trip system to actuate. If either trip system actuates, both recirculation pumps will trip from fast speed operation. There are two EOC-RPT breakers in series

(continued)

BASES

BACKGROUND (continued)	per recirculation pump. One trip system trips one of the two EOC-RPT breakers for each recirculation pump and the second trip system trips the other EOC-RPT breaker for each recirculation pump.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The TSV Closure and the TCV Fast Closure, Trip Oil Pressure-Low Functions are designed to trip the recirculation pumps from fast speed operation in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and pressure transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in References 1, 2, and 3. To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps from fast speed operation after initiation of initial closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. The EOC-RPT function is automatically disabled when turbine first stage pressure is < 38% RTP. EOC-RPT instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time. Allowable Values are specified for each EOC-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. A channel is inoperable if

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

its actual trip setpoint is not within its required Allowable Value. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual parameter (e.g., TCV electrohydraulic control (EHC) pressure), and when the measured output value of the parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analysis, LCO, and Applicability discussions are listed below on a Function by Function basis.

<u>Turbine Stop Valve Closure</u>

Closure of the TSVs and a main turbine trip result in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an EOC-RPT is initiated on TSV Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring the MCPR SL is not exceeded during the worst case transient.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	Turbine Stop Valve Closure (continued) Closure of the TSVs is determined by a limit switch on each stop valve. There is one limit switch associated with each stop valve, and the signal from each limit switch is assigned to a separate trip channel. The logic for the TSV Closure is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 38% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening the turbine bypass valve may affect the Function. Four channels of TSV Closure, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV Closure Allowable Value is selected high enough to detect imminent TSV closure. This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 38% RTP with any recirculation pump in fast speed. Below 38% RTP or with the recirculation pump in slow speed, the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor (APRM) Fixed Neutron Flux-High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

TCV Fast Closure, Trip Oil Pressure-Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an EOC-RPT is initiated on TCV Fast Closure, Trip Oil Pressure-Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the EHC fluid pressure at each control valve. There is one pressure switch associated with each control valve, and the signal from each switch is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure-Low Function is such that two or more TCVs must be closed (pressure switch trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 38% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, opening the turbine bypass valve may affect the Function. Four channels of TCV Fast Closure, Trip Oil Pressure-Low, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure-Low Allowable Value is selected high enough to detect imminent TCV fast closure.

This protection is required consistent with the analysis, whenever the THERMAL POWER is ≥ 38% RTP with any recirculating pump in fast speed. Below 38% RTP or with recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure-High and the APRM Fixed Neutron Flux-High Functions of the RPS are adequate to maintain the necessary safety margins.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to EOC-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable EOC-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable EOC-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Action B.1 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of an EOC-RPT, 72 hours is allowed to restore the inoperable channels (Required Action A.1). Alternately, the inoperable channels may be placed in trip (Required Action A.2) since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted in Required Action A.2, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case

(continued)

BASES

ACTIONS

A.1 (continued)

where placing the inoperable channel in trip would result in an EOC-RPT), or if the inoperable channel is the result of an inoperable breaker, Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining EOC-RPT trip capability. A Function is considered to be maintaining EOC-RPT trip capability when sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped from fast speed operation. This requires two channels of the Function, in the same trip system, to be OPERABLE or in trip, and the associated EOC-RPT fast speed breakers to be OPERABLE or in trip.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2, "MCPR," Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 38% RTP within 4 hours. Alternately, the associated recirculation pump fast speed breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 38% RTP from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

This Note is based on the reliability analysis (Ref. 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

SR 3.3.4.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.4.1.2

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.3

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would also be inoperable.

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

SR 3.3.4.1.4

This SR ensures that an EOC-RPT initiated from the TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 38% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed during in-service calibration at THERMAL POWER ≥ 38% RTP, to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 38% RTP either due to open main turbine bypass valves or other reasons), the affected TSV Closure and TCV Fast Closure, Trip Oil Pressure-Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition (Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are enabled), this SR is met with the channel considered OPERABLE.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.5

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. The EOC-RPT SYSTEM RESPONSE TIME acceptance criteria are included in Reference 5.

A Note to the Surveillance states that breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. This is allowed since the arc suppression time is short and does not appreciably change.

Each EOC-RPT SYSTEM RESPONSE TIME test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested at the required frequency. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.1.6

This SR ensures that the RPT breaker arc suppression time is provided to the EOC-RPT SYSTEM RESPONSE TIME test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 7.6.1.6.
2. USAR, Section 5.2.2.
3. USAR, Sections 15.1.1, 15.1.2, and 15.1.3.

(continued)

BASES

REFERENCES (continued)	4.	Deleted.
	5.	GE DSDS 22A6083.

B 3.3 INSTRUMENTATION

B 3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND

The ATWS-RPT System initiates a recirculation pump trip, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level – Low Low, Level 2 or Reactor Vessel Pressure – High setpoint is reached, the recirculation pump motor breakers trip.

The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability, circuit breakers, and switches that are necessary to cause initiation of a recirculation pump trip. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an ATWS-RPT signal to the trip logic.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Pressure – High and two channels of Reactor Vessel Water Level – Low Low, Level 2, in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Vessel Water Level – Low Low, Level 2 or two Reactor Vessel Pressure – High signals are needed to trip a trip system. The output of the trip system initiated by Reactor Vessel Water Level – Low Low, Level 2, will trip both recirculation pumps (by tripping the respective fast speed and low frequency motor generator (LFMG) motor breakers). The output of the trip system initiated by Reactor Vessel Pressure – High will trip the respective fast speed motor breakers and transfer the recirculation pumps to the LFMG sets. The LFMG motor breakers will then be tripped if an APRM downscale condition does not occur within 25 seconds (Ref. 1).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The ATWS-RPT is not assumed in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which scram does not, but should, occur. Based on its contribution to the reduction of overall plant risk, however, the instrumentation is included as required by the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

The OPERABILITY of the ATWS-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.2.4. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump drive motor breakers. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Allowable Values are specified for each ATWS-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The individual Functions are required to be OPERABLE in MODE 1 to protect against common mode failures of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Protection System by providing a diverse trip to mitigate the consequences of a postulated ATWS event. The Reactor Vessel Water Level-Low Low, Level 2 and Reactor Vessel Pressure-High Functions are required to be OPERABLE in MODE 1, since the reactor is producing significant power and the recirculation system could be at high flow. During this MODE, the potential exists for pressure increases or low water level, assuming an ATWS event. In MODE 2, the reactor is at low power and the recirculation system is at low flow; thus, the potential is low for a pressure increase or low water level, assuming an ATWS event. Therefore, the ATWS-RPT is not necessary. In MODES 3 and 4, the reactor is shut down with all control rods inserted; thus, an ATWS event is not significant and the possibility of a significant pressure increase or low water level is negligible. In MODE 5, the one-rod-out interlock ensures the reactor remains subcritical; thus, an ATWS event is not significant. In addition, the reactor pressure vessel (RPV) head is not fully tensioned and no pressure transient threat to the reactor coolant pressure boundary (RCPB) exists.

The specific Applicable Safety Analyses and LCO discussions are listed below on a Function by Function basis.

a. Reactor Vessel Water Level – Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the ATWS-RPT System is initiated at Level 2 to aid in maintaining level above the top of the active fuel. The reduction of core flow reduces the neutron flux and THERMAL POWER and, therefore, the rate of coolant boiloff.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Level – Low Low, Level 2, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<u>a. Reactor Vessel Water Level – Low Low, Level 2</u> (continued) The Reactor Vessel Water Level – Low Low, Level 2, Allowable Value is chosen so that the system will not initiate after a Level 3 scram with feedwater still available, and for convenience with the reactor core isolation cooling (RCIC) initiation. <u>b. Reactor Vessel Pressure – High</u> Excessively high RPV pressure may rupture the RCPB. An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This increases neutron flux and THERMAL POWER, which could potentially result in fuel failure and RPV overpressurization. The Reactor Vessel Pressure – High Function initiates an ATWS-RPT for transients that result in a pressure increase, counteracting the pressure increase by rapidly reducing core power generation. For the overpressurization event, the ATWS-RPT aids in the termination of the ATWS event and, along with the safety/relief valves (S/RVs), limits the peak RPV pressure to less than the ASME Section III Code Service Level C limits (1500 psig). The Reactor Vessel Pressure – High signals are initiated from four pressure transmitters that monitor reactor steam dome pressure. Four channels of Reactor Vessel Pressure – High, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. The Reactor Vessel Pressure – High Allowable Value is chosen to provide an adequate margin to the ASME Section III Code Service Level C allowable Reactor Coolant System pressure.
ACTIONS	A Note has been provided to modify the ACTIONS related to ATWS-RPT instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required

(continued)

BASES

ACTIONS (continued)

Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ATWS-RPT instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable ATWS-RPT instrumentation channel.

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT capability for each Function maintained (refer to Required Action B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desirable to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an ATWS-RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS (continued)

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system to each be OPERABLE or in trip, and the four motor breakers (two fast speed and two LFMG) to be OPERABLE or in trip.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and the fact that one Function is still maintaining ATWS-RPT trip capability.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within both Functions result in both Functions not maintaining ATWS-RPT trip capability. The description of a Function maintaining ATWS-RPT trip capability is discussed in the Bases for Required Action B.1, above.

The 1 hour Completion Time is sufficient for the operator to take corrective action and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period.

D.1 and D.2

With any Required Action and associated Completion Time not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours (Required Action D.2). Alternately, the associated recirculation pump may be removed from service since this

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

performs the intended Function of the instrumentation (Required Action D.1). The allowed Completion Time of 6 hours is reasonable, based on operating experience, both to reach MODE 2 from full power conditions and to remove a recirculation pump from service in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

SR 3.3.4.2.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2.1 (continued)

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.4.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.4.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.2.4. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.4.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers, included as part of this Surveillance, overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel(s) would be also inoperable.

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

REFERENCES

1. USAR, Section 7.6.1.12.

2. GENE-770-06-1, "Bases For Changes To Surveillance Test Intervals and Allowed Out-of-Service Times For Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

The purpose of the ECCS instrumentation is to initiate appropriate responses from the systems to ensure that fuel is adequately cooled in the event of a design basis accident or transient.

For most anticipated operational occurrences (AOOs) and Design Basis Accidents (DBAs), a wide range of dependent and independent parameters are monitored.

Portions of this ECCS instrumentation actuate the Annulus Exhaust Gas Treatment (AEGT) subsystems and the diesel generators (DGs), in addition to the ECCS subsystems (Low Pressure Core Spray (LPCS), Low Pressure Coolant Injection (LPCI), High Pressure Core Spray (HPCS), and Automatic Depressurization System (ADS)). The supported systems are described in the Bases for:

- LCO 3.5.1 and 3.5.2 “ECCS-Operating” and “Reactor Pressure Vessel (RPV) Water Inventory Control”
- LCO 3.6.4.3 “Annulus Exhaust Gas Treatment (AEGT) System,” and
- LCO 3.8.1 and 3.8.2 “AC Sources-Operating” and “AC Sources-Shutdown”.

Low Pressure Core Spray System

The LPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low Low, Level 1 or Drywell Pressure - High. Each of these diverse variables is monitored by two redundant transmitters, which are, in turn, connected to two trip units. The outputs of the four trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The initiation signal is a sealed in signal and must be manually reset. The logic can also be initiated by use of a manual push button. Upon receipt of an initiation signal, the LPCS pump is started immediately after power is available.

The LPCS test valve to suppression pool, which is also a primary containment isolation valve (PCIV), is closed on a LPCS initiation signal to allow full system flow assumed in the accident analysis and maintains containment isolation in the event LPCS is not operating.

(continued)

BASES

BACKGROUND

Low Pressure Core Spray System (continued)

The LPCS pump discharge flow is monitored by a flow transmitter. When the pump is running and discharge flow is low enough that pump overheating may occur, the minimum flow valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The LPCS System also monitors the pressure in the reactor vessel to ensure that, before the injection valve opens, the reactor pressure has fallen to a value below the LPCS System's maximum design pressure. The variable is monitored by one pressure transmitter, which is, in turn, connected to a trip unit.

Low Pressure Coolant Injection Subsystems

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with three LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level – Low Low Low, Level 1 or Drywell Pressure – High. Each of these diverse variables is monitored by two redundant transmitters per Division, which are, in turn, connected to two trip units. The outputs of the four Division 2 LPCI (loops B and C) trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Division 1 LPCI (loop A) receives its initiation signal from the LPCS logic, which uses a similar one-out-of-two taken twice logic. The two Divisions can also be initiated by use of a manual push button (one per Division). Once an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

Upon receipt of an initiation signal, the LPCI Pump C is started immediately after power is available while LPCI A and LPCI B pumps are started after a 5 second delay, to limit the loading on the standby power sources.

Each LPCI subsystem's discharge flow is monitored by a flow transmitter. When a pump is running and discharge flow is low enough that pump overheating may occur, the respective

(continued)

BASES

BACKGROUND

Low Pressure Coolant Injection Subsystems (continued)

minimum flow valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the analyses.

The RHR test valves to suppression pool (which are also PCIVs) are closed on a LPCI initiation signal to allow full system flow assumed in the accident analysis and maintain containment isolated in the event LPCI is not operating.

The LPCI subsystems monitor the pressure in the reactor vessel to ensure that, prior to an injection valve opening, the reactor pressure has fallen to a value below the LPCI subsystem's maximum design pressure. The variable is monitored by one pressure transmitter per subsystem, which is, in turn, connected to a trip unit. When pressure drops below the trip setpoint, a permissive signal is sent to the control logic for the injection valve in that subsystem.

High Pressure Core Spray System

The HPCS System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level – Low Low, Level 2 or Drywell Pressure – High. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic for each variable. The HPCS System initiation signal is a sealed in signal and must be manually reset.

The HPCS pump discharge flow is monitored by a flow transmitter and a pump discharge pressure transmitter. When the pump is running as indicated by high discharge pressure and discharge flow is low enough that pump overheating may occur, the minimum flow valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow full system flow assumed in the accident analyses.

The HPCS test valve to suppression pool (which is also a PCIV) is closed on a HPCS initiation signal to allow full system flow assumed in the accident analyses and maintain containment isolated in the event HPCS is not operating.

(continued)

BACKGROUND

High Pressure Core Spray System (continued)

The HPCS System also monitors the water levels in the condensate storage tank (CST) and the suppression pool, since these are the two sources of water for HPCS operation. Reactor grade water in the CST is the normal and preferred source. However, only the capability to take suction from the suppression pool is required for OPERABILITY. Upon receipt of a HPCS initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position), unless the suppression pool suction valve is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. Two level transmitters are used to detect low water level in the CST. Either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. Similarly, two level transmitters are used to detect high water level in the suppression pool. The suppression pool suction valve also automatically opens and the CST suction valve closes if high water level is detected in the suppression pool. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The HPCS System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip, at which time the HPCS injection valve closes. The HPCS pump will continue to run on minimum flow. The logic is one-out-of-two taken twice to provide high reliability of the HPCS System. The injection valve automatically reopens if a low low water level signal is subsequently received.

Automatic Depressurization System

ADS may be initiated by either automatic or manual means. Automatic initiation occurs when signals indicating Reactor Vessel Water Level-Low Low Low, Level 1; confirmed Reactor Vessel Water Level-Low, Level 3; and either LPCS or LPCI Pump Discharge Pressure-High are all present, and the ADS Initiation Timer has timed out. There are two transmitters

(continued)

BASES

BACKGROUND

Automatic Depressurization System (continued)

for Reactor Vessel Water Level—Low Low Low, Level 1, and one transmitter for confirmed Reactor Vessel Water Level—Low, Level 3 in each of the two ADS trip systems. Each of these transmitters connects to a trip unit, which then drives a relay whose contacts form the initiation logic.

Each ADS trip system (trip system A and trip system B) includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The time delay chosen is long enough that the HPCS has time to operate to recover to a level above Level 1, yet not so long that the LPCI and LPCS systems are unable to adequately cool the fuel if the HPCS fails to maintain level. An alarm in the control room is annunciated when either of the timers is running. Resetting the ADS initiation signals resets the ADS Initiation Timers.

The ADS also monitors the discharge pressures of the three LPCI pumps and the LPCS pump. Each ADS trip system includes two discharge pressure permissive transmitters from each of the two low pressure ECCS pumps in the associated Division (i.e., Division 1 ECCS inputs to ADS trip system A and Division 2 ECCS inputs to ADS trip system B). The signals are used as a permissive for ADS actuation, indicating that there is a source of core coolant available once the ADS has depressurized the vessel. Any one of the four low pressure pumps provides sufficient core coolant flow to permit automatic depressurization.

The ADS logic in each trip system is arranged in two channels. One channel has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3; ADS Initiation Timer; and two low pressure ECCS Pump Discharge Pressure—High contacts. The other channel has a contact from each of the following variables: Reactor Vessel Water Level—Low Low Low, Level 1, and two low pressure ECCS Pump Discharge Pressure—High contacts. To initiate an ADS trip system, the following applicable contacts must close in the associated channel: Reactor Vessel Water Level—Low Low Low, Level 1; Reactor Vessel Water Level—Low, Level 3; ADS Initiation Timer; and one of the two low pressure ECCS Pump Discharge Pressure—High contacts.

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BACKGROUND

Automatic Depressurization System (continued)

Either ADS trip system A or trip system B will cause all the ADS relief valves to open. Once the ADS initiation signal is present, it is sealed in until manually reset.

There are two manual initiation push buttons in each trip system. Actuating both push buttons in either trip system will cause all ADS valves to open if at least one of the two low pressure ECCS pumps is running. Manual initiation can also be accomplished by operating the individual control switch for each safety/relief valve (S/RV) associated with the ADS. Manual inhibit switches are provided in the control room for ADS; however, their function is not required for ADS OPERABILITY (provided ADS is not inhibited when required to be OPERABLE).

Diesel Generators

The Division 1, 2, and 3 DGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level-Low Low Low, Level 1 or Drywell Pressure-High for Division 1 and 2 DGs, and Reactor Vessel Water Level-Low Low, Level 2 or Drywell Pressure-High for Division 3 DG. The DGs are also initiated upon degraded voltage and loss of voltage signals (refer to Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals). Each of these diverse variables is monitored by two redundant transmitters per DG, which are, in turn, connected to two trip units. The outputs of the four divisionalized trip units (two trip units from each of the two variables) are connected to relays whose contacts are connected to a one-out-of-two taken twice logic. The DGs receive their initiation signals from the associated Divisions' ECCS logic (i.e., Division 1 DG receives an initiation signal from Division 1 ECCS (LPCS and LPCI A); Division 2 DG receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C); and Division 3 DG receives an initiation signal from Division 3 ECCS (HPCS)). The DGs can also be started manually from the control room and locally in the associated DG room. The DG initiation signal is a sealed in signal and must be manually reset. The DG initiation logic is reset by resetting the associated ECCS initiation logic. Upon receipt of a LOCA initiation signal, each DG is automatically started, is ready to load in approximately 10 seconds (13 seconds for Division 3), and will run in

(continued)

BACKGROUND

Diesel Generators (continued)

standby conditions (rated voltage and speed, with the DG output breaker open). The DGs will only energize their respective Engineered Safety Feature (ESF) buses if a degraded voltage or loss of voltage occurs (refer to Bases for LCO 3.3.8.1).

AEGTs

The AEGT subsystems may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level-Low Low Low, Level 1 or Drywell Pressure-High. Each of these diverse variables is monitored by two redundant transmitters per AEGT subsystem which are, in turn, connected to two trip units. The outputs of the four divisionalized trip units (two trip units from each of the two variables) are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The AEGT subsystems receive their initiation signals from the associated Divisions' ECCS logic (i.e., Division 1 AEGT subsystem receives an initiation signal from Division 1 ECCS (LPCS and LPCI A), and Division 2 AEGT subsystem receives an initiation signal from Division 2 ECCS (LPCI B and LPCI C)). The AEGT subsystems can also be started manually from the control room. The AEGT initiation logic is reset by resetting the associated ECCS initiation logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the ECCS are explicitly assumed in the safety analyses of References 1, 2, and 3. The ECCS is initiated to preserve the integrity of the fuel cladding by limiting the post LOCA peak cladding temperature to less than the 10 CFR 50.46 limits.

ECCS instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the ECCS instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each ECCS subsystem must also respond within its assumed response time. Table 3.3.5.1-1 is modified by a footnote. Footnote (b) is added to show that certain ECCS instrumentation Functions also perform DG and AEGT subsystem initiation.

Allowable Values are specified for each ECCS Function specified in the table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or AEGT) initiation to mitigate the consequences of a design basis accident or transient. To ensure reliable ECCS and AEGT function, a combination of Functions is required to provide primary and secondary initiation signals. The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Low Pressure Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Vessel Water Level - Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated DGs are initiated at Level 1 to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The AEGT System also receives Level 1 initiation signals to ensure a subsystem will operate following events that challenge core coverage. The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Vessel Water Level - Low Low Low, Level 1 Function is assumed in the analysis of the DBA LOCA (Ref. 2). The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low Low Low, Level 1 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling.

Two channels of Reactor Vessel Water Level - Low Low Low, Level 1 Function per associated Division are required to be OPERABLE when the associated ECCS or AEGT subsystem is required to be OPERABLE, to ensure that no single instrument failure can preclude system initiation. (Two channels input to Division 1, while the other two channels input to Division 2.)

Refer to LCO 3.5.1, “ECCS-Operating,” for Applicability Bases for the low pressure ECCS subsystems and LCO 3.6.4.3, “Annulus Exhaust Gas Treatment (AEGT) System,” for Applicability Bases for AEGT System.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b, 2.b. Drywell Pressure-High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The low pressure ECCS and associated DGs are initiated upon receipt of the Drywell Pressure-High Function in order to minimize the possibility of fuel damage. The AEGT System also receives Drywell Pressure-High signals to ensure a subsystem will operate following a DBA LOCA. The Drywell Pressure-High Function is assumed in the analysis of the DBA LOCA (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

High drywell pressure signals are initiated from four pressure transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment. Negative barometric fluctuations are accounted for in the Allowable Value.

The Drywell Pressure-High Function is required to be OPERABLE when the associated ECCS, DGs or AEGT subsystems are required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the LPCS and LPCI Drywell Pressure-High Function are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude system initiation. (Two channels input to Division 1, while the other two channels input to Division 2.) In MODES 4 and 5, the Drywell Pressure-High Function is not required since there is insufficient energy in the reactor to pressurize the primary containment to Drywell Pressure-High setpoint.

Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems; LCO 3.8.1 for Applicability Bases for the DGs; and LCO 3.6.4.3 for Applicability Bases for the AEGT subsystems.

1.c, 2.c. Low Pressure Coolant Injection Pump A and Pump B Start-Time Delay Relay

The purpose of this time delay is to stagger the start of the two ECCS pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV emergency buses. This Function is only necessary when power is being supplied from the standby power sources (DG).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 2.c. Low Pressure Coolant Injection Pump A and Pump B Start - Time Delay Relay (continued)

However, since the time delay does not degrade ECCS operation, it remains in the pump start logic at all times. The LPCI Pump Start - Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analysis assumes that the pumps will initiate when required and excess loading will not cause failure of the power sources.

There are two LPCI Pump Start - Time Delay Relays, one in each of the RHR "A" and RHR "B" pump start logic circuits. While each time delay relay is dedicated to a single pump start logic, a single failure of a LPCI Pump Start - Time Delay Relay could result in the failure of the two low pressure ECCS pumps, powered from the same ESF bus, to perform their intended function within the assumed ECCS RESPONSE TIMES (e.g., as in the case where both ECCS pumps on one ESF bus start simultaneously due to an inoperable time delay relay). This still leaves two of the four low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). The Allowable Value for the LPCI Pump Start - Time Delay Relay is chosen to be long enough so that most of the starting transient of the first pump is complete before starting the second pump on the same 4.16 kV emergency bus and short enough so that ECCS operation is not degraded.

Each LPCI Pump Start - Time Delay Relay Function is only required to be OPERABLE when the associated LPCI subsystem is required to be OPERABLE. Refer to LCO 3.5.1 for Applicability Bases for the LPCI subsystems.

1.d, 1.e, 2.d. Reactor Vessel Pressure - Low (Injection Valve Permissive)

Low reactor vessel pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Vessel Pressure - Low (Injection Valve Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition,

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.d, 1.e, 2.d. Reactor Vessel Pressure - Low (Injection Valve Permissive) (continued)

the Reactor Vessel Pressure - Low (Injection Valve Permissive) Function is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Vessel Pressure - Low (Injection Valve Permissive) signals are initiated from one pressure transmitter for each low pressure ECCS System that senses the reactor pressure.

The Allowable Value is low enough to prevent overpressurizing the equipment in the low pressure ECCS, but high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

One channel of Reactor Vessel Pressure - Low (Injection Valve Permissive) Function per associated low pressure ECCS subsystem is required to be OPERABLE when the associated ECCS is required to be OPERABLE. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

1.f, 1.g, 2.e. Low Pressure Coolant Injection and Low Pressure Core Spray Pump Discharge Flow - Low (Bypass)

The minimum flow instruments are provided to protect the associated low pressure ECCS pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The LPCI and LPCS Pump Discharge Flow - Low (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the low pressure ECCS flows assumed during the transients and accidents analyzed in References 1, 2, and 3 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. One flow transmitter per ECCS pump is used to detect the associated subsystems' flow rates.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.f, 1.g, 2.e. Low Pressure Coolant Injection and Low Pressure Core Spray Pump Discharge Flow - Low (Bypass) (continued)

The logic is arranged such that each transmitter causes its associated minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 8 seconds after the transmitters and associated trip units detect low flow. The time delay is provided to limit reactor vessel inventory loss during the startup of the RHR shutdown cooling mode (for RHR A and RHR B). The Pump Discharge Flow - Low (Bypass) Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of Pump Discharge Flow - Low (Bypass) Function (one LPCS channel and three LPCI channels) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE, to ensure that no single instrument failure can preclude the ECCS function. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

1.h, 2.f. Manual Initiation

The Manual Initiation push button channels introduce signals into the appropriate ECCS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There is one push button for each of the two Divisions of low pressure ECCS (i.e., Division 1 ECCS, LPCS and LPCI A; Division 2 ECCS, LPCI B and LPCI C).

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the low pressure ECCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons. Each channel of the Manual Initiation Function (one channel per Division) is only required to be OPERABLE when the associated ECCS is required to be OPERABLE. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

High Pressure Core Spray System

3.a. Reactor Vessel Water Level - Low Low, Level 2

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCS System and associated DG is initiated at Level 2 to maintain level above the top of the active fuel. The Reactor Vessel Water Level - Low Low, Level 2 is one of the Functions assumed to be OPERABLE and capable of initiating HPCS during the transients analyzed in References 1 and 3. The Reactor Vessel Water Level - Low Low, Level 2 Function associated with HPCS is assumed in the analysis of a DBA LOCA (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low Low, Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - Low Low, Level 2 Allowable Value is chosen such that for complete loss of feedwater flow, the Reactor Core Isolation Cooling (RCIC) System flow with HPCS assumed to fail will be sufficient to avoid initiation of low pressure ECCS at Reactor Vessel Water Level - Low Low Low, Level 1.

Four channels of Reactor Vessel Water Level - Low Low, Level 2 Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS initiation. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.b. Drywell Pressure – High

High pressure in the drywell could indicate a break in the RCPB. The HPCS System and associated DG are initiated upon receipt of the Drywell Pressure - High Function in order to minimize the possibility of fuel damage. The Drywell Pressure - High Function is assumed in the analysis of

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.b. Drywell Pressure-High (continued)

a DBA LOCA (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

This Function is not considered to be inoperable with indicated reactor vessel water level on the wide range instrument greater than the Level 8 setpoint coincident with the reactor steam dome pressure < 450 psig since the HPCS System would provide the necessary injection if required (i.e., if the water level reaches the low water level initiation setpoint).

Drywell Pressure-High signals are initiated from four pressure transmitters that sense drywell pressure. The Allowable Value was selected to be as low as possible and be indicative of a LOCA inside primary containment.

The Drywell Pressure-High Function is required to be OPERABLE when HPCS is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the HPCS Drywell Pressure-High Function are required to be OPERABLE in MODES 1, 2, and 3, to ensure that no single instrument failure can preclude ECCS initiation. In MODES 4 and 5, the Drywell Pressure-High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure-High Function's setpoint. Refer to LCO 3.5.1 for the Applicability Bases for the HPCS System.

3.c. Reactor Vessel Water Level-High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the HPCS injection valve to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level-High, Level 8 Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk. Reactor Vessel Water Level-High, Level 8 signals for HPCS are initiated from four level transmitters from the wide range water level

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.c. Reactor Vessel Water Level - High, Level 8 (continued)

measurement instrumentation. The instruments are arranged in a one-out-of-two taken twice logic. This ensures that no single instrument failure can preclude HPCS initiation. The Reactor Vessel Water Level - High, Level 8 Allowable Value is chosen to isolate flow from the HPCS System prior to water overflowing into the MSLs.

Four channels of Reactor Vessel Water Level - High, Level 8 Function are only required to be OPERABLE when HPCS is required to be OPERABLE. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.d. Condensate Storage Tank Level – Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valve between HPCS and the CST is open and, upon receiving a HPCS initiation signal, water for HPCS injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCS pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Condensate Storage Tank Level - Low signals are initiated from two level transmitters. The logic is arranged such that either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. The Condensate Storage Tank Level - Low Function Allowable Value of 90,300 gallons (elevation 626 ft. 8 inches) is high enough to ensure adequate pump suction head while water is being taken from the CST.

Two channels of the Condensate Storage Tank Level - Low Function are only required to be OPERABLE when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. Thus, the Function is required to be OPERABLE

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.d. Condensate Storage Tank Level – Low (continued)

in MODES 1, 2, and 3. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.e. Suppression Pool Water Level – High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the S/RVs. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCS from the CST to the suppression pool to eliminate the possibility of HPCS continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes. This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCS) since the analyses assume that the HPCS suction source is the suppression pool.

Suppression Pool Water Level - High signals are initiated from two level transmitters. The logic is arranged such that either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. The Allowable Value for the Suppression Pool Water Level - High Function is chosen to ensure that HPCS will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level - High Function are only required to be OPERABLE in MODES 1, 2, and 3 when HPCS is required to be OPERABLE to ensure that no single instrument failure can preclude HPCS swap to suppression pool source. In MODES 4 and 5, the Function is not required to be OPERABLE since the reactor is depressurized and vessel

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e. Suppression Pool Water Level – High (continued)

blowdown, which could cause the design values of the containment to be exceeded, cannot occur. Refer to LCO 3.5.1 for HPCS Applicability Bases.

3.f, 3.g. HPCS Pump Discharge Pressure - High (Bypass) and HPCS System Flow Rate - Low (Bypass)

The minimum flow instruments are provided to protect the HPCS pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow valve is opened when low flow and high pump discharge pressure are sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump or the discharge pressure is low (indicating the HPCS pump is not operating). The HPCS System Flow Rate – Low (Bypass) and HPCS Pump Discharge Pressure - High (Bypass) Functions are assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents analyzed in References 1, 2, and 3 is met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow transmitter is used to detect the HPCS System's flow rate. The logic is arranged such that the transmitter causes the minimum flow valve to open, provided the HPCS pump discharge pressure, sensed by another transmitter, is high enough (indicating the pump is operating). The logic will close the minimum flow valve once the closure setpoint is exceeded. (The valve will also close upon HPCS pump discharge pressure decreasing below the setpoint.)

The HPCS System Flow Rate - Low (Bypass) and HPCS Pump Discharge Pressure - High (Bypass) Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core. The HPCS Pump Discharge Pressure - High (Bypass) Allowable Value is set high enough to ensure that the valve will not be open when the pump is not operating.

One channel of each Function is required to be OPERABLE when the HPCS is required to be OPERABLE. Refer to LCO 3.5.1 for HPCS Applicability Bases.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.h. Manual Initiation

The Manual Initiation push button channel introduces a signal into the HPCS logic to provide manual initiation capability and is redundant to the automatic protective instrumentation. There is one push button for the HPCS System. The Manual Initiation consists of a single channel in a single trip system.

This Function is not considered to be inoperable with indicated reactor vessel water level on the wide range instrument greater than the Level 8 setpoint coincident with the reactor steam dome pressure < 450 psig since the HPCS System would provide the necessary injection if required (i.e., if the water level reaches the low water level initiation setpoint).

The Manual Initiation Function is not assumed in any accident or transient analysis in the USAR. However, the Function is retained for overall redundancy and diversity of the HPCS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button. One channel of the Manual Initiation Function is only required to be OPERABLE when the HPCS System is required to be OPERABLE. Refer to LCO 3.5.1 for HPCS Applicability Bases.

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level - Low Low Low, Level 1

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this Function. The Reactor Vessel Water Level - Low Low Low, Level 1 is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accidents analyzed in Reference 2. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a, 5.a. Reactor Vessel Water Level - Low Low Low, Level 1 (continued)

Reactor Vessel Water Level - Low Low Low, Level 1 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Low, Level 1 Function are only required to be OPERABLE when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (Two channels input to ADS trip system A while the other two channels input to ADS trip system B). Refer to LCO 3.5.1 for ADS Applicability Bases.

The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is high enough to allow time for the low pressure core flooding systems to initiate and provide adequate cooling.

4.b, 5.b. ADS Initiation Timer

The purpose of the ADS Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCS System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCS System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the timer, or to inhibit initiation permanently. The ADS Initiation Timer Function is assumed to be OPERABLE for the accident analyses of Reference 2 that require ECCS initiation and assume failure of the HPCS System.

There are two ADS Initiation Timer relays, one in each of the two ADS trip systems. The Allowable Value for the ADS Initiation Timer is chosen to be short enough so that there is still time after depressurization for the low pressure ECCS subsystems to provide adequate core cooling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.b, 5.b. ADS Initiation Timer (continued)

Two channels of the ADS Initiation Timer Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.c, 5.c. Reactor Vessel Water Level – Low, Level 3

The Reactor Vessel Water Level – Low, Level 3 Function is used by the ADS only as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level – Low Low Low, Level 1 signals. In order to prevent spurious initiation of the ADS due to spurious Level 1 signals, a Level 3 signal must also be received before ADS initiation commences.

Reactor Vessel Water Level – Low, Level 3 signals are initiated from two level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Allowable Value for Reactor Vessel Water Level – Low, Level 3 is selected at the RPS Level 3 scram Allowable Value for convenience. Refer to LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," for Bases discussion of this Function.

Two channels of Reactor Vessel Water Level – Low, Level 3 Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. (One channel inputs to ADS trip system A while the other channel inputs to ADS trip system B.) Refer to LCO 3.5.1 for ADS Applicability Bases.

4.d, 4.e, 5.d. Low Pressure Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure – High

The Pump Discharge Pressure – High signals from the LPCS and LPCI pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure – High is one of the Functions assumed to be OPERABLE and capable of permitting ADS

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.d, 4.e, 5.d. Low Pressure Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure - High (continued)

initiation during the events analyzed in References 2 and 3 with an assumed HPCS failure. For these events, the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Pump discharge pressure signals are initiated from eight pressure transmitters, two on the discharge side of each of the four low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure - High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode, and high enough to avoid any condition that results in a discharge pressure permissive when the LPCS and LPCI pumps are aligned for injection and the pumps are not running. The actual operating point of this Function is not assumed in any transient or accident analysis.

Eight channels of LPCS and LPCI Pump Discharge Pressure - High Function (two LPCS and two LPCI A channels input to ADS trip system A, while two LPCI B and two LPCI C channels input to ADS trip system B) are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Refer to LCO 3.5.1 for ADS Applicability Bases.

4.f, 5.e. Manual Initiation

The Manual Initiation push button channels introduce signals into the ADS logic to provide manual initiation capability and are redundant to the automatic protective instrumentation. There are two push buttons for each ADS trip system (total of four).

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for overall redundancy and diversity of the ADS function as required by the NRC in the plant licensing basis.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.f, 5.e. Manual Initiation (continued)

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push buttons. Four channels of the Manual Initiation Function (two channels per ADS trip system) are only required to be OPERABLE when the ADS is required to be OPERABLE. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

A Note has been provided to modify the ACTIONS related to ECCS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable ECCS instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable ECCS instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.1-1. The applicable Condition specified in the table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1, B.2, and B.3

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function (or in some cases, within the same monitored parameter) result in redundant automatic initiation capability being lost for the feature(s). Required Action B.1 "features" would be those that are initiated by Functions 1.a, 1.b, 2.a, and 2.b (e.g., Division 1 and 2 diesel generators, low pressure ECCS, or the AEGT subsystems); B.1 features do not include those separately addressed with their own Instrumentation Specification (e.g., RHR Containment Spray Instrumentation). The Required Action B.2 feature would be HPCS.

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

For Required Action B.1, redundant automatic initiation capability is lost for a feature if either (a) one or more of its Function 1.a channels and one or more of its Function 2.a channels are inoperable and untripped, or (b) one or more of its Function 1.b channels and one or more of its Function 2.b channels are inoperable and untripped. Since Required Action B.1 is only applicable if channels supporting both Divisions of a feature are inoperable and untripped, the affected portions of both Divisions of ECCS, DG and AEGT are declared inoperable concurrently (within 1 hour of discovery).

For Required Action B.2, redundant automatic initiation capability is lost if two Function 3.a or two Function 3.b channels are inoperable and untripped in the same trip system.

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action B.3 is not appropriate and the feature(s) associated with the inoperable, untripped channels must be declared inoperable within 1 hour.

Required Action B.1 and Required Action B.2, are only applicable in MODES 1, 2, and 3. Notes are also provided (Note to Required Action B.1 and Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed.

(continued)

ACTIONS

B.1, B.2, and B.3 (continued)

The Completion Time 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." For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in both Divisions (e.g., any Division 1 ECCS and any Division 2 ECCS; the Division 1 and 2 DGs; the Division 1 and 2 AEGT subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same monitored parameter as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCS System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function (or in some cases, within the same monitored parameter) result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.c, 1.d, 1.e, 2.c, and 2.d (i.e., low pressure ECCS). For Functions 1.c and 2.c, redundant automatic initiation capability is lost if the Function 1.c and Function 2.c channels are inoperable. For Functions 1.d, 1.e, and 2.d, redundant automatic initiation capability is lost if the Function 1.d and 1.e channels and the Function 2.d channels are inoperable. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated Division to be declared inoperable. However, since channels in both Divisions are inoperable, and the Completion Times started concurrently for the channels in both Divisions, this results in the affected portions in both Divisions being concurrently declared inoperable. For Functions 1.c and 2.c, the affected portions of the Division are LPCI A and LPCI B, respectively. For Functions 1.d, 1.e, and 2.d, the affected portions of the Division are the low pressure ECCS pumps (Divisions 1 and 2, respectively).

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the feature(s) associated with the inoperable channels must be declared inoperable within 1 hour.

The Note states that Required Action C.1 is only applicable for Functions 1.c, 1.d, 1.e, 2.c, and 2.d. The Required Action is not applicable to Functions 1.h, 2.f, and 3.h (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed. Required Action C.1 is also not applicable to Function 3.c. since the loss of the Function was considered during the development of Reference 4 and considered acceptable for the 24 hours allowed by Required Action C.2.

The Completion Time 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." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both Divisions (e.g., any Division 1 ECCS and Division 2 ECCS) cannot be automatically initiated due to inoperable channels within the same monitored parameter as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or would not necessarily result in a safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCS System. Automatic component initiation capability is lost if two Function 3.d channels or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCS

(continued)

BASES

ACTIONS

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

System must be declared inoperable within 1 hour after discovery of loss of HPCS initiation capability. As noted, the Required Action is only applicable if the HPCS pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

The Completion Time 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." For Required Action D.1, the Completion Time only begins upon discovery that the HPCS System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or Required Action D.2.2 is performed, measures should be taken to ensure that the HPCS System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2, Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

channels within the LPCS and LPCI Pump Discharge Flow - Low (Bypass) Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.f, 1.g, and 2.e (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if three of the four channels associated with Functions 1.f, 1.g, and 2.e are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the feature(s) associated with each inoperable channel must be declared inoperable within 1 hour after discovery of loss of initiation capability for feature(s) in both Divisions. A Note is also provided (the Note to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCS Functions 3.f and 3.g since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 4 and considered acceptable for the 7 days allowed by Required Action E.2.

The Completion Time 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." For Required Action E.1, the Completion Time only begins upon discovery that three channels of the Function (Pump

(continued)

ACTIONS

E.1 and E.2 (continued)

Discharge Flow—Low (Bypass)) cannot be automatically initiated due to inoperable channels. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation such that the valve would not automatically close, a portion of the pump flow could be diverted from the reactor injection path, causing insufficient core cooling. These consequences can be averted by the operator's manual control of the valve, which would be adequate to maintain ECCS pump protection and required flow. Furthermore, other ECCS pumps would be sufficient to complete the assumed safety function if no additional single failure were to occur. The 7 day Completion Time of Required Action E.2 to restore the inoperable channel to OPERABLE status is reasonable based on the remaining capability of the associated ECCS subsystems, the redundancy available in the ECCS design, and the low probability of a DBA occurring during the allowed out of service time. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

F.1 and F.2

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one or more Function 4.a channel(s) and one or more Function 5.a channel(s) are inoperable and untripped, or (b) one Function 4.c channel and one Function 5.c channel are inoperable and untripped.

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action F.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems.

The Completion Time 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." For Required Action F.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE. If either HPCS or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable, (b) one or more Function 4.d channels and one or more Function 5.d channels are inoperable, or (c) one or more Function 4.e channels and one or more Function 5.d channels are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability in both trip systems. The Note to Required Action G.1 states that Required Action G.1 is only applicable for Functions 4.b, 4.d, 4.e, 5.b, and 5.d. Required Action G.1 is not applicable to Functions 4.f and 5.e (which also require entry into this Condition if a channel in these Functions is inoperable), since they are the Manual Initiation Functions and are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 96 hours or 8 days (as allowed by Required Action G.2) is allowed.

The Completion Time 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." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions, as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 4) to permit restoration of any inoperable channel to OPERABLE status if both HPCS and RCIC are OPERABLE (Required Action G.2). If either HPCS or RCIC is

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

inoperable, the time is reduced to 96 hours. If the status of HPCS or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCS or RCIC inoperability. However, total time for an inoperable channel cannot exceed 8 days. If the status of HPCS or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

H.1

With any Required Action and associated Completion Time of Condition B, C, D, E, F, or G not met, the associated feature(s) may be incapable of performing the intended function and the supported feature(s) associated with the inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours as follows: (a) for Functions 3.c, 3.f, 3.g, and 3.h; and (b) for Functions other than 3.c, 3.f, 3.g, and 3.h provided the associated Function or the redundant Function maintains ECCS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ECCS will initiate when necessary.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.5.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be not within its required

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SURVEILLANCE REQUIREMENTS

SR 3.3.5.1.3 (continued)

Allowable Value specified in Table 3.3.5.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analyses. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

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

SR 3.3.5.1.4, SR 3.3.5.1.5 and SR 3.3.5.1.7

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.5.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

The HPCS LOGIC SYSTEM FUNCTIONAL TEST Surveillance may be performed in any mode.

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BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.3.5.1.6</u> (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 5.2. 2. USAR, Section 6.3. 3. USAR, Chapter 15. 4. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988. 5. Plant Data Book, Tab R, Section 6.2.9.

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control Instrumentation

BASES

BACKGROUND

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

Technical Specifications are required by 10 CFR 50.36 to include limiting safety system settings (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 safety action is initiated 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 actual settings for the automatic isolation channels are the same as those established for the same functions in MODES 1, 2, and 3 in LCO 3.3.6.1, “Primary Containment and Drywell Isolation Instrumentation.”

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur. Under the definition of DRAIN TIME, some penetration flow paths may be excluded from the DRAIN TIME calculation if they will be isolated by valves that will close automatically without offsite power prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation.

(continued)

BASES

BACKGROUND (continued)	The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control,” and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal subsystem and Reactor Water Cleanup system penetration flow path(s) on low RPV water level.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material should a draining event occur.
	A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure. It is assumed, based on engineering judgment, that while in MODES 4 and 5, one ECCS injection/spray subsystem can be manually initiated to maintain adequate reactor vessel water level.
	As discussed in References 1, 2, 3, 4, and 5, operating experience has shown RPV water inventory to be significant to public health and safety. Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
	Permissive and interlock setpoints are generally considered as nominal values without regard to measurement accuracy. The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed as follows on a Function by Function basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

RHR System Isolation

1.a. Reactor Vessel Water Level – Low, Level 3

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being automatically isolated by RPV water level isolation instrumentation prior to the RPV water level being equal to the TAF.

The Reactor Vessel Water Level – Low, Level 3 Function is only required to be OPERABLE when automatic isolation of the associated RHR penetration flow path is credited in calculating DRAIN TIME.

Reactor Vessel Water Level – Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level – Low, Level 3 Function are available, only two channels of the Reactor Vessel Water Level – Low, Level 3 Function are required to be OPERABLE.

The Reactor Vessel Water Level – Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level – Low, Level 3 Allowable Value (LCO 3.3.1.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 3 and 4 valves.

Reactor Water Cleanup (RWCU) System Isolation

2.a. Reactor Vessel Water Level – Low Low, Level 2

The definition of DRAIN TIME allows crediting the closing of penetration flow paths that are capable of being automatically isolated by RPV water level isolation instrumentation prior to the RPV water level being equal to the TAF. The Reactor Vessel Water Level – Low Low, Level 2 Function associated with RWCU System isolation may be credited for automatic isolation of penetration flow paths associated with the RWCU System.

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to isolate the potential sources of a break.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Reactor Vessel Water Level – Low Low, Level 2 (continued)

Reactor Vessel Water Level – Low Low, Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. While four channels (two channels per trip system) of the Reactor Vessel Water Level – Low Low, Level 2 Function are available, only two channels (all in the same trip system) are required to be OPERABLE.

The Reactor Vessel Water Level – Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level – Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low Low, Level 2 Function is only required to be OPERABLE when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME.

This Function isolates the Group 7 valves.

ACTIONS

A Note has been provided to modify the ACTIONS related to RPV Water Inventory Control instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPV Water Inventory Control instrumentation channels provide appropriate compensatory measures for separate inoperable Condition entry for each inoperable RPV Water Inventory Control instrumentation channel.

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

RHR System Isolation, Reactor Vessel Water Level – Low Level 3, and Reactor Water Cleanup System, Reactor Vessel Water Level – Low Low, Level 2 functions are applicable when automatic isolation of the associated penetration flow path is credited in calculating DRAIN TIME. If the instrumentation is inoperable, Required Action A.1 directs immediate action to place the channel in trip. With the inoperable channel in the

(continued)

BASES

ACTIONS

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

tripped condition, the remaining channel will isolate the penetration flow path on low water level. If both channels are inoperable and placed in trip, the penetration flow path will be isolated. Alternatively, Required Action A.2.1 requires that the associated penetration flow path(s) to be immediately declared incapable of automatic isolation. Required Action A.2.2 directs initiating action to calculate DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

SURVEILLANCE REQUIREMENTS

The following SRs apply to each RPV Water Inventory Control Instrument Function in Table 3.3.5.2-1.

SR 3.3.5.2.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK guarantees that undetected outright channel failure is limited; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL FUNCTIONAL TEST.

Agreement criteria are determined by the plant 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 instrument has drifted outside its limit.

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

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2.2 (continued)

performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

REFERENCES

1. Information Notice 84-81, "Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup," November 1984.

2. Information Notice 86-74, "Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves," August 1986.

3. Generic Letter 92-04, "Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)," August 1992.

4. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," May 1993.

5. Information Notice 94-52, "Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1," July 1994.

B 3.3 INSTRUMENTATION

B 3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

The purpose of the RCIC System instrumentation is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is unavailable, such that initiation of the low pressure Emergency Core Cooling Systems (ECCS) pumps does not occur. A more complete discussion of RCIC System operation is provided in the Bases of LCO 3.5.3, "RCIC System."

The RCIC System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level-Low Low, Level 2. The variable is monitored by four transmitters that are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic arrangement. Once initiated, the RCIC logic seals in and can be reset by the operator only when the reactor vessel water level signals have cleared.

The RCIC CST first and second test return valves close on a RCIC initiation signal to allow full system flow. The RCIC System also monitors the water levels in the condensate storage tank (CST) and the suppression pool, since these are the two sources of water for RCIC operation. Reactor grade water in the CST is the normal source. However, only the capability to take suction from the suppression pool is required for OPERABILITY. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction from the suppression pool valve is open. If the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. Two level transmitters are used to detect low water level in the CST. Either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. Similarly, two level transmitters are used to detect high water level in the suppression pool. The suppression pool suction valve also automatically opens and the CST suction valve closes if high water level is detected in the suppression pool. To prevent losing suction to the pump,

(continued)

BASES

BACKGROUND (continued)

the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the high water level (Level 8) trip (two-out-of-two logic), at which time the RCIC steam supply valve closes (the injection valve also closes due to the closure of the steam supply valve). The RCIC System restarts if vessel level again drops to the low level initiation point (Level 2).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The function of the RCIC System is to provide makeup coolant to the reactor in response to transient events. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analysis for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the RCIC System, and therefore its instrumentation, are included as required by the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RCIC System instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.3-1. Each Function must have a required number of OPERABLE channels with their setpoints within the specified Allowable Values, where appropriate. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RCIC System instrumentation Function specified in the table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Each Allowable Value specified accounts for instrument uncertainties appropriate to the Function. These uncertainties are described in the setpoint methodology.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The individual Functions are required to be OPERABLE in MODE 1, and in MODES 2 and 3 with reactor steam dome pressure > 150 psig, since this is when RCIC is required to be OPERABLE. (Refer to LCO 3.5.3 for Applicability Bases for the RCIC System.)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Reactor Vessel Water Level - Low Low, Level 2

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level - Low Low, Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - Low Low, Level 2 Allowable Value is set high enough such that for complete loss of feedwater flow, the RCIC System flow (with high pressure core spray assumed to fail) will be sufficient to avoid initiation of low pressure ECCS at Level 1.

Four channels of Reactor Vessel Water Level - Low Low, Level 2 Function are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

2. Reactor Vessel Water Level - High, Level 8

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Level 8 signal is used to close the RCIC steam supply valve to prevent overflow

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Reactor Vessel Water Level - High, Level 8 (continued)

into the main steam lines (MSLs). (The injection valve also closes due to the closure of the steam supply valve.)

Reactor Vessel Water Level - High, Level 8 signals for RCIC are initiated from four level transmitters from the wide range water level measurement instrumentation, which sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - High, Level 8 Allowable Value is high enough to preclude isolating the injection valve of the RCIC during normal operation, yet low enough to trip the RCIC System prior to water overflowing into the MSLs.

Four channels of Reactor Vessel Water Level - High, Level 8 Function are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC initiation. Refer to LCO 3.5.3 for RCIC Applicability Bases.

3. Condensate Storage Tank Level - Low

Low level in the CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valve between the RCIC pump and the CST is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from the CST. However, if the water level in the CST falls below a preselected level, first the suppression pool suction valve automatically opens and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes.

Condensate Storage Tank Level-Low signals are initiated from two level transmitters. The logic is arranged such that either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. The Condensate Storage Tank Level-Low Function Allowable Value of 90,300 gallons (elevation 626 ft. 8 inches) is high enough to ensure adequate pump suction head while water is being taken from the CST.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Condensate Storage Tank Level – Low (continued)

Two channels of Condensate Storage Tank Level - Low Function are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to the suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

4. Suppression Pool Water Level - High

Excessively high suppression pool water level could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety/relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of RCIC from the CST to the suppression pool to eliminate the possibility of RCIC continuing to provide additional water from a source outside primary containment. This Function satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valve must be open before the CST suction valve automatically closes.

Suppression Pool Water Level - High signals are initiated from two level transmitters. The logic is arranged such that either transmitter and associated trip unit can cause the suppression pool suction valve to open and the CST suction valve to close. The Allowable Value for the Suppression Pool Water Level - High Function is chosen to ensure that RCIC will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level - High Function are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to the suppression pool source. If the automatic transfer of the suction source for RCIC from the CST to the suppression pool, due to a high suppression pool water level signal, is manually overridden by the operator, then the Suppression Pool Water Level-High Functions are considered inoperable. Refer to LCO 3.5.3 for RCIC Applicability Bases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Manual Initiation

The Manual Initiation push button switch introduces a signal into the RCIC System initiation logic that is redundant to the automatic protective instrumentation and provides manual initiation capability. There is one push button for the RCIC System.

The Manual Initiation Function is not assumed in any accident or transient analyses in the USAR. However, the Function is retained for the RCIC function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button. One channel of Manual Initiation is required to be OPERABLE when RCIC is required to be OPERABLE.

ACTIONS

A Note has been provided to modify the ACTIONS related to RCIC System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RCIC System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RCIC System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.5.3-1 in the accompanying LCO. The applicable Condition referenced in the Table is Function dependent. Each time a channel is discovered to be inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this case, automatic initiation capability is lost if two Function 1 channels in the same trip system are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time 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." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level - Low Low, Level 2 channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

(continued)

BASES

ACTIONS (continued)

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1), limiting the allowable out of service time if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level - High, Level 8 Function. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours is allowed. The Required Action does not allow placing a channel in trip since this action would not necessarily result in the safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this case, automatic component initiation capability is lost if two Function 3 channels or two Function 4 channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

The Completion Time 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." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour

(continued)

ACTIONS

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

Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time of Condition B, C, or D not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 5; and (b) for up to 6 hours for Functions 1, 2, 3, and 4 provided the associated

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 1) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.3.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.3.2 (continued)

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

SR 3.3.5.3.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.5.3-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be re-adjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.5.3.4 and SR 3.3.5.3.6

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter with the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.5.3.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

(continued)

BASES

SURVEILLANCE	SR 3.3.5.3.5 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. GENE-770-06-2, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment and Drywell Isolation Instrumentation

BASES

BACKGROUND

The primary containment and drywell isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs) and the drywell isolation valves. The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre- established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (a) reactor vessel water level, (b) ambient temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) condenser vacuum loss, (f) main steam line pressure, (g) reactor core isolation cooling (RCIC) steam line flow, (h) ventilation exhaust radiation, (i) RCIC steam line pressure, (j) RCIC turbine exhaust diaphragm pressure, (k) reactor water cleanup (RWCU) differential flow, (l) reactor steam dome pressure, and (m) drywell pressure. Redundant sensor input signals are provided from each such isolation initiation parameter. The only exception is SLC System initiation. In addition, manual isolation of the logic is provided.

(continued)

BACKGROUND (continued)

The primary containment and drywell isolation instrumentation has inputs to the trip logic from the isolation Functions listed below.

1. Main Steam Line Isolation

Most Main Steam Line Isolation Functions receive inputs from four channels. The outputs from these channels are combined in one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate all MSL drain valves. One logic trip system isolates one valve in the inboard MSL drain line. The other trip system isolates the second valve in the inboard MSL drain line.

The exception to this arrangement is the Main Steam Line Flow-High Function. This Function uses 16 flow channels, four for each steam line. If one or more of the 16 flow channels are inoperable, then the appropriate Conditions and Required Actions must be entered. One flow channel from each steam line inputs to one of four trip channels. Two trip channels make up each trip system, and both trip systems must trip to cause an MSL isolation. Each trip channel has four inputs (one per MSL), any one of which will trip the trip channel. The trip channels within a trip system are arranged in a one-out-of-two taken twice logic. Therefore, this is effectively a one-out- of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one- out-of-four twice logic). One logic trip system isolates one valve in the inboard MSL drain line. The other trip system isolates the second valve in the inboard MSL drain line.

2. Primary Containment and Drywell Isolation

Each Primary Containment Isolation Function receives inputs from four channels. The outputs from these channels are arranged into two two-out-of-two logic trip systems. One trip system initiates isolation of all inboard PCIVs and drywell isolation valves, while the other trip system initiates isolation of all outboard PCIVs. Each trip system

(continued)

BASES

BACKGROUND

2. Primary Containment and Drywell Isolation (continued)

logic closes one of the two valves on each penetration so that operation of either trip system isolates the penetration.

3. Reactor Core Isolation Cooling System Isolation

Most Functions receive input from two channels, with each channel in one trip system using one-out-of-one logic. Function 3.h (RHR Equipment Area Temperature) has one channel in each trip system in each room for a total of four channels, but the logic is the same (one-out-of-one). Each of the two trip systems is connected to one of the two valves on each RCIC penetration so that operation of either trip system isolates the penetration. The exception to this arrangement is the RCIC Turbine Exhaust Diaphragm Pressure—High Function. This Function receives input from four turbine exhaust diaphragm pressure channels. The outputs from the turbine exhaust diaphragm pressure channels are connected into two two-out-of-two trip systems, each trip system isolating one of the two RCIC valves. There is only one manual initiation push button which can isolate only the outboard RCIC system containment isolation valves.

4. Reactor Water Cleanup System Isolation

Most Functions receive input from two channels with each channel in one trip system using one-out-of-one logic. Function 4.d (RWCU Pump Room Temperature) and Function 4.h (RWCU Demineralizer Room Temperature) have one channel in each trip system in each room for a total of four channels, but the logic is the same (one-out-of-one). Each of the two trip systems is connected to one of the two valves on each RWCU penetration so that operation of either trip system isolates the penetration. The exception to this arrangement is the Reactor Vessel Water Level—Low Low, Level 2 Function. This Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected into two two-out-of-two trip systems, each trip system isolating one of the two RWCU valves.

(continued)

BACKGROUND (continued)

5. RHR System Isolation

The RHR System Isolation Function receives input signals from instrumentation for the Reactor Vessel Water Level-Low, Level 3; Drywell Pressure-High; Reactor Vessel Steam Dome Pressure-High; RHR Equipment Area Ambient Temperature-High Functions; and Manual Initiation. The Reactor Vessel Water Level-Low, Reactor Vessel Steam Dome Pressure-High, and Drywell Pressure-High Functions each have four channels. The outputs from the reactor vessel water level and drywell pressure channels are connected into two two-out- of-two trip systems. The reactor vessel steam dome pressure is arranged into two one-out-of-two trip systems. The RHR Equipment Area Ambient Temperature Function receives input from four channels with each channel in one trip system in one room using one-out-of-one logic. Each of the two trip systems is connected to one of the two valves on each RHR System shutdown cooling penetration so that operation of either trip system isolates the penetration.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment and drywell isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases, for more detail. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell. Refer to LCO 3.6.5.3, "Drywell Isolation Valves," Applicable Safety Analyses Bases, for more detail.

Primary containment and drywell isolation instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the primary containment and drywell instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	specified Allowable Values, where appropriate. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Each channel must also respond within its assumed response time, where appropriate.

Allowable Values are specified for each Primary Containment and Drywell Isolation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

Certain Emergency Core Cooling Systems (ECCS) and RCIC valves (e.g., minimum flow) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS and RCIC. Some instrumentation and ACTIONS associated with these signals are addressed in LCO 3.3.5.1, “ECCS Instrumentation,” and LCO 3.3.5.3, “RCIC Instrumentation,” and are not included in this LCO.

In general, the individual Functions are required to be OPERABLE in MODES 1, 2, and 3 consistent with the Applicability for LCO 3.6.1.1, “Primary Containment-Operating” or LCO 3.6.5.1, “Drywell,” as

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

applicable. Functions that have different Applicabilities are discussed below in the individual Functions discussion.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. Main Steam Line Isolation

1.a. Reactor Vessel Water Level-Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level-Low Low Low, Level 1 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level-Low Low Low, Level 1 Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 1). The isolation of the MSL on Level 1 supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level-Low Low Low, Level 1 Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level-Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Level 1 Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 50.67 limits (Ref. 8).

This Function isolates the Group 6 valves.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b Main Steam Line Pressure – Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level conditions and the RPV cooling down more than 100°F/hour if the pressure loss is allowed to continue. The Main Steam Line Pressure-Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hour) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs during the depressurization transient in order to maintain reactor steam dome pressure > 686 psig. The MSIV closure results in a scram, thus reducing reactor power to < 23.8% RTP.)

The MSL low pressure signals are initiated from four transmitters that are connected to the MSL header. The transmitters are arranged such that, even though physically separated from each other, each transmitter is able to detect low MSL pressure. Four channels of Main Steam Line Pressure-Low Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be high enough to prevent excessive RPV depressurization.

The Main Steam Line Pressure-Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 2).

This Function isolates the Group 6 valves.

1.c Main Steam Line Flow – High

Main Steam Line Flow-High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow-High Function is directly assumed in the analysis of the main steam line break (MSLB) accident (Ref. 1). The isolation action, along with the scram function of the RPS,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c. Main Steam Line Flow-High (continued)

ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 50.67 limits (Ref. 8).

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. The transmitters are arranged such that, even though physically separated from each other, all four connected to one steam line would be able to detect the high flow. Four channels of Main Steam Line Flow-High Function for each unisolated MSL (two channels per trip system) are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL. If one or more of the 16 flow transmitters or associated flow channels are inoperable, then the appropriate Conditions and Required Actions must be entered.

The Allowable Value is chosen to ensure that offsite dose limits are not exceeded due to the break.

This Function isolates the Group 6 valves.

1.d. Condenser Vacuum-Low

The Condenser Vacuum-Low Function is provided to prevent overpressurization of the main condenser in the event of a loss of the main condenser vacuum. Since the integrity of the condenser is an assumption in offsite dose calculations, the Condenser Vacuum-Low Function is assumed to be OPERABLE and capable of initiating closure of the MSIVs. The closure of the MSIVs is initiated to prevent the addition of steam that would lead to additional condenser pressurization and possible rupture of the diaphragm installed to protect the turbine exhaust hood, thereby preventing a potential radiation leakage path following an accident.

Condenser vacuum pressure signals are derived from four pressure transmitters that sense the pressure in the condenser. Four channels of Condenser Vacuum-Low Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to prevent damage to the condenser due to pressurization, thereby ensuring its integrity for offsite dose analysis. As noted (footnote (a) to Table 3.3.6.1-1), the channels are not required to be

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.d. Condenser Vacuum-Low (continued)

OPERABLE in MODES 2 and 3, when all turbine stop valves (TSVs) are closed, since the potential for condenser overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

This Function isolates the Group 6 valves.

1.e, 1.f. Main Steam Line Pipe Tunnel Ambient Temperature-High, Main Steam Line Turbine Building Temperature-High

Ambient Temperature-High is provided to detect a leak in the RCPB, and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSLBs.

Ambient temperature signals are initiated from thermocouples located in the area being monitored. Four channels of both Main Steam Line Pipe Tunnel Temperature-High and Main Steam Line Turbine Building Temperature-High Functions are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The ambient temperature monitoring Allowable Value is chosen to detect a leak equivalent to 25 gpm in the steam tunnel and 280 gpm in the Turbine Building.

These Functions isolate the Group 6 valves.

1.g. Manual Initiation

The Manual Initiation push button channels introduce signals into the MSL isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for the isolation function as required by the NRC in the plant licensing basis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.h. Manual Initiation (continued)

There are four push buttons for the logic, two manual initiation push buttons per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of Manual Initiation Function are required to be OPERABLE.

2. Primary Containment and Drywell Isolation

2.a, 2.e. Reactor Vessel Water Level-Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on Level 2 supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded (Ref. 8). The Reactor Vessel Water Level-Low Low, Level 2 Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA. In addition, Function 2.a provides an isolation signal to certain drywell isolation valves. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

Reactor Vessel Water Level-Low Low, Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level-Low Low, Level 2 Function are required to be OPERABLE to ensure no single instrument failure can preclude the isolation function. Function 2.e (Division 3) has only one trip system consisting of four channels logically combined in a one-out-of-two twice configuration.

The Reactor Vessel Water Level-Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level-Low Low, Level 2 Allowable Value (LCO 3.3.5.1),

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a, 2.e. Reactor Vessel Water Level-Low Low, Level 2 (continued)

since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the 1E22-F023 Valve (Function 2.e), and the Group 1, 5, 7, and 8 valves (Function 2.a).

2.b, 2.d, 2.f Drywell Pressure-High

High drywell pressure can indicate a break in the RCPB. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded (Ref. 8). The Drywell Pressure-High Function associated with isolation of the primary containment is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA. In addition, Functions 2.b and 2.d provide isolation signals to certain drywell isolation valves. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

High drywell pressure signals are initiated from four pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure-High per Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Function 2.f (Division 3) has only one trip system consisting of four channels logically combined in a one-out-of-two twice configuration.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure-High Allowable Value (LCO 3.3.5.1), since

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

<u>2.b, 2.d, 2.f Drywell Pressure-High</u> (continued)

this may be indicative of a LOCA inside primary containment.

These Functions isolate the Group 1, 5, and 8 valves (Function 2.b), Group 2 and, in conjunction with Function 3.c, the 1E51-F068, the 1E51-F077, and the 1E51-F078 valves from Group 9 (Function 2.d), and the 1E22-F023 valve (Function 2.f).

<u>2.c. Reactor Vessel Water Level-Low Low Low, Level 1</u>

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the primary containment occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level-Low Low Low, Level 1 Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level-Low Low Low, Level 1 Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA. In addition, this Function provides an isolation signal to certain drywell isolation valves. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level Low- Low-Low, Level 1 Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level-Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level-Low Low Low, Level 1 Allowable Value (LCO 3.3.5.1) to ensure the valves are isolated to prevent offsite doses from exceeding 10 CFR 50.67 limits (Ref. 8).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.c. Reactor Vessel Water Level-Low Low Low, Level 1 (continued)

This Function isolates the Group 2 isolation valves.

2.g. Containment and Drywell Purge Exhaust-Plenum Radiation-High

High purge exhaust plenum radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB. When Purge Exhaust-Plenum Radiation-High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products. In addition, this Function provides an isolation signal to certain drywell isolation valves. The isolation of drywell isolation valves, in combination with other accident mitigation systems, functions to ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

The Purge Exhaust-Plenum Radiation-High signals are initiated from four radiation detectors that are located on the purge exhaust plenum ductwork coming from the drywell and containment. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.g Containment and Drywell Purge Exhaust-Plenum Radiation-High (continued)

Four channels of Containment and Drywell Purge Exhaust-Plenum Radiation-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. Containment and Drywell Purge System inboard and outboard isolation valves each use a separate two-out-of-two isolation logic.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding and to ensure offsite doses remain below 10 CFR 20 and 10 CFR 50.67 limits.

Due to radioactive decay, handling of fuel only requires OPERABILITY of this Function when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 12).

These Functions isolate the Group 8 valves.

2.h. Manual Initiation

The Manual Initiation push button channels introduce signals into the primary containment and drywell isolation logic that

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.h. Manual Initiation (continued)

are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for the isolation function as required by the NRC in the plant licensing basis.

There are four push buttons for the logic, two manual initiation push buttons per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of the Manual Initiation Function are required to be OPERABLE in MODES 1, 2, and 3, and during movement of recently irradiated fuel assemblies in primary containment, since these are the MODES in which the Primary Containment and Drywell Isolation automatic Functions are required to be OPERABLE. Due to radioactive decay, handling of fuel only requires OPERABILITY of this Function when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 12).

The manual initiation channels for the RCIC System is discussed in Section 3.k below, and for the HPCS System is discussed in the Bases description for ECCS Instrumentation (LCO 3.3.5.1).

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Core Isolation Cooling System Isolation

3.a. RCIC Steam Line Flow-High

RCIC Steam Line Flow-High Function is provided to detect a break of the RCIC steam lines and initiates closure of the steam line isolation valves. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and core uncovery can occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for this Function is not assumed in any USAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC Steam Line Flow-High signals are initiated from two transmitters that are connected to the system steam lines. Two channels of RCIC Steam Line Flow-High Functions are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.a. RCIC Steam Line Flow-High (continued)

This Function isolates the Group 9 valves.

3.b. RCIC Steam Line Flow Time Delay

The RCIC Steam Line Flow Time Delay is provided to prevent false isolations on RCIC Steam Line Flow-High during system startup transients and therefore improves system reliability. This Function is not assumed in any USAR transient or accident analyses.

The Allowable Value was chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

Two channels for RCIC Steam Line Flow Time Delay Functions are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

3.c. RCIC Steam Supply Line Pressure-Low

Low RCIC steam supply line pressure indicates that the pressure of the steam may be too low to continue operation of the RCIC turbine. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the USAR. However, it also provides a diverse signal to indicate a possible system break. These instruments are included in the Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing RCIC initiations.

The RCIC Steam Supply Line Pressure-Low signals are initiated from two transmitters that are connected to the system steam line. Two channels of RCIC Steam Supply Line Pressure-Low Functions are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is selected to be high enough to prevent damage to the RCIC system turbine.

This Function in conjunction with Function 3.j, isolates the 1E51-F068, 1E51-F077, and 1E51-F078 valves in Group 9.

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

3.d. RCIC Turbine Exhaust Diaphragm Pressure-High

High turbine exhaust diaphragm pressure indicates that the pressure may be too high to continue operation of the associated system turbine. That is, one of two exhaust diaphragms has ruptured and pressure is reaching turbine

casing pressure limits. This isolation is for equipment protection and is not assumed in any transient or accident analysis in the USAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing RCIC initiations (Ref. 3).

The RCIC Turbine Exhaust Diaphragm Pressure–High signals are initiated from four transmitters that are connected to the area between the rupture diaphragms on the RCIC turbine exhaust line. Four channels of RCIC Turbine Exhaust Diaphragm Pressure–High Functions are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are low enough to prevent damage to the RCIC system turbine.

This Function isolates the Group 9 valves.

3.e, 3.h. Ambient Temperature–High

Ambient Temperatures are provided to detect a leak from the associated system steam piping. The isolation occurs when a very small leak has occurred and is diverse to the high flow instrumentation. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. This Function is not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Ambient Temperature–High signals are initiated from thermocouples that are appropriately located to protect the system that is being monitored. Two instruments monitor each area. Six channels for RHR and RCIC Equipment Area Ambient Temperature–High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. There are two for the RCIC room and four for the RHR area.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.e, 3.h. Ambient Temperature-High (continued)

The Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 9 valves.

3.f. Main Steam Line Pipe Tunnel Ambient Temperature-High

Ambient Temperature High is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSLBs.

Ambient temperature signals are initiated from thermocouples located in the area being monitored. Two channels of Main Steam Line Pipe Tunnel Temperature-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to detect a leak equivalent to 25 gpm.

This Function isolates the Group 9 valves.

3.g. Main Steam Line Pipe Tunnel Temperature Timer

The Main Steam Line Pipe Tunnel Temperature Timer is provided to allow all the other systems that may be leaking in the main steam tunnel (as indicated by the high temperature) to be isolated before RCIC is automatically isolated. This ensures maximum RCIC System operation by preventing isolations due to leaks in other systems. This Function is not assumed in any USAR transient or accident analysis; however, maximizing RCIC availability is an important function.

Two channels for RCIC Main Steam Line Pipe Tunnel Timer Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.g. Main Steam Line Pipe Tunnel Temperature Timer (continued)

The Allowable Values are based on maximizing the availability of the RCIC System; that is, providing sufficient time to isolate all other potential leakage sources in the main steam tunnel before RCIC is isolated.

This Function isolates the Group 9 valves.

3.i. RCIC Steam Line Flow-High (Ten-Inch Line)

RCIC high steam line flow is provided to detect a break of the RCIC ten-inch steam line and initiates closure of the RCIC isolation valves. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. Therefore, the isolation is initiated at high flow to prevent or minimize core damage. Specific credit for this Function is not assumed in any USAR accident or transient analysis since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC steam line break from becoming bounding.

The RCIC steam line flow signals are initiated from two transmitters that are connected to the ten-inch steam line. Two channels of the RCIC Steam Line Flow-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Allowable Value is selected to ensure that the trip occurs to prevent fuel damage and maintains the MSLB as the bounding event.

This Function actuates the Group 9 valves.

3.j. Drywell Pressure-High

High drywell pressure can indicate a break in the RCPB. The RCIC isolation of the turbine exhaust is provided to prevent communication with the drywell when high drywell pressure exists. A potential leakage path exists via the turbine exhaust. The isolation is delayed until the system becomes unavailable for injection (i.e., low steam line pressure). The isolation of the RCIC turbine exhaust by Drywell Pressure-High is indirectly assumed in the USAR accident analysis because the turbine exhaust leakage path is not assumed to contribute to offsite doses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3.j. Drywell Pressure—High (continued)

The high drywell pressure signal is initiated from a pressure transmitter that senses the pressure in the drywell. One channel of RCIC Drywell Pressure—High Function is required to be OPERABLE.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure—High Allowable Value (LCO 3.3.5.1), since this is indicative of a LOCA inside primary containment. This Function in conjunction with Function 3.c isolates the 1E51-F068, 1E51-F077, and 1E51-F078 valves in Group 9.

3.k. Manual Initiation

The Manual Initiation push button channel introduces a signal into the RCIC System isolation logic that is redundant to the automatic protective instrumentation and provides manual isolation capability if an initiation signal is present. There is no specific USAR safety analysis that takes credit for this Function. It is retained the isolation function as required by the NRC in the plant licensing basis.

There is only one push button for RCIC, in a single trip system. There is no Allowable Value for this Function since the channel is mechanically actuated based solely on the position of the push button.

One channel of RCIC Manual Initiation is required to be OPERABLE.

4. Reactor Water Cleanup System Isolation

4.a. Differential Flow—High

The high differential flow signal is provided to detect a break in the RWCU System. This will detect leaks in the RWCU System when area or differential temperature would not provide detection (i.e., a cold leg break). Should the reactor coolant continue to flow out of the break, offsite dose limits may be exceeded. Therefore, isolation of the RWCU System is initiated when high differential flow is sensed to prevent exceeding offsite doses. A time delay is provided to prevent spurious trips during most RWCU operational transients. This Function is not assumed in any USAR transient or accident analysis, since bounding analyses

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.a Differential Flow-High (continued)

are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from two transmitters that are connected to the inlet (from the reactor vessel) and four transmitters from the outlets (blowdown to condenser/rad waste and feedwater) of the RWCU System. The outputs of the transmitters are compared (in two different summers) and the outputs are sent to two high flow trip units. If the difference between the inlet and outlet flow is too large, each trip unit generates an isolation signal. Two channels of Differential Flow-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Water Cleanup Differential Flow-High Allowable Value ensures that the break of the RWCU piping is detected.

This Function isolates the Group 7 valves.

4.b. Differential Flow-Timer

The Differential Flow-Timer is provided to avoid RWCU System isolations due to operational transients (such as pump starts and mode changes). During these transients the inlet and outlet flows become unbalanced for short time periods and Differential Flow-High will be sensed without an RWCU System break being present. Credit for this Function is not assumed in the USAR accident or transient analysis, since bounding analyses are performed for large breaks such as MSLBs. The Differential Flow Timer Allowable Value is selected to ensure that the MSLB outside containment remains the limiting break for USAR analysis for offsite dose calculations.

Two channels for Differential Flow - Timer Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

4.c, 4.d, 4.e, 4.f, 4.g, 4.h. Ambient Temperature High

Ambient Temperature - High is provided to detect a leak from the RWCU System. The isolation occurs even when very small leaks have occurred and is diverse to the high differential flow instrumentation for the hot portions of the RWCU

(continued)

BASES

APPLICABLE LCO, and APPLICABILITY

4.c, 4.d, 4.e, 4.f, 4.g, 4.h (continued)

System. If the small leak continues without isolation, offsite dose limits may be reached. Credit for these instruments is not taken in any transient or accident analysis in the USAR, since bounding analyses are performed for large breaks such as MSLBs.Ambient temperature signals are initiated from temperature elements that are located in the room that is being monitored. There are sixteen thermocouples that provide input to the Area Temperature—High Function (two per area). Sixteen channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Ambient Temperature—High Allowable Values are set low enough to detect a leak equivalent to 25 gpm.

These Functions isolate the Group 7 valves.

4.i Main Steam Line Pipe Tunnel Ambient Temperature - High

Ambient Temperature - High is provided to detect a leak in the RCPB and provides diversity to the high flow instrumentation. The isolation occurs when a very small leak has occurred. If the small leak is allowed to continue without isolation, offsite dose limits may be reached. However, credit for these instruments is not taken in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Ambient temperature signals are initiated from thermocouples located in the area being monitored. Two channels of Main Steam Line Pipe Tunnel Temperature - High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value is chosen to detect a leak equivalent to 25 gpm.

This Function isolates the Group 7 values.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4.j. Reactor Vessel Water Level - Low Low, Level 2

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level - Low Low, Level 2 Function associated with RWCU isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Reactor Vessel Water Level-Low Low, Level 2 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low, Level 2 Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low Low, Level 2 Allowable Value was chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low, Level 2 Allowable Value (LCO 3.3.5.1), since the capability to cool the fuel may be threatened.

This Function isolates the Group 7 valves.

4.k. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 4). SLC System initiation signals are initiated from the two SLC pump start signals.

There is no Allowable Value associated with this Function since the channels are mechanically actuated based solely on the position of the SLC System initiation switch.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4.k. SLC System Initiation (continued)

Two channels (one from each pump) of SLC System Initiation Function are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7).

4.l. Manual Initiation

The Manual Initiation push button channels introduce signals into the RWCU System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for the isolation function as required by the NRC in plant licensing basis.

There are four push buttons for the logic, two manual initiation push buttons per trip system. There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of the Manual Initiation Function are required to be OPERABLE.

5. RHR System Isolation

5.a. Ambient Temperature-High

RCIC steam piping still remains in the RHR equipment areas even after elimination of the Steam Condensing Mode of RHR, and a break in that portion of the steam pipe could result in increased temperatures in the RHR equipment areas. The requirements over the Ambient Temperature-High circuits which address isolation of such RCIC steam leaks in the RHR areas are provided by Function 3.h, "RCIC System Isolation, RHR Equipment Area Ambient Temperature-High", rather than by this Function (Function 5.a, which is an "RHR System Isolation").

The function of the RHR System Isolation Ambient Temperature-High instrumentation is to provide a diverse method from the Reactor Vessel Water Level-Low Level 3

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a. Ambient Temperature-High (continued)

instruments for detecting a leak from RHR system piping which connects to the Reactor Coolant Pressure Boundary (RCPB) (Ref. 14). When a small or large leak is detected, the function also initiates an automatic RHR isolation to terminate further leakage from the RCPB. If a small leak is allowed to continue without isolation, offsite dose limits may be reached. This Function is not assumed in any USAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

Ambient Temperature-High signals are initiated from thermocouples that are appropriately located to protect the system that is being monitored. Two instruments monitor each RHR equipment area. Four channels for RHR Ambient Temperature-High

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.a. Ambient Temperature-High (continued)

Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The RHR System Isolation Ambient Temperature - High Function is only required to be OPERABLE in MODES 2 and 3 when the reactor vessel steam dome pressure is less than the RHR cut in permissive pressure. This is the only period when the valves in Valve Groups 3 and 4 which serve to isolate the RCPB (i.e., 1E12-F008, F009, F023, F053A and B) can be open, since in MODE 1 and in MODES 2 and 3 when the reactor vessel pressure is above the RHR cut in permissive pressure, a diverse signal from the Reactor Steam Dome Pressure-High Function will maintain the RHR RCPB isolation valves in these groups isolated. There are additional valves other than the five RCPB isolation valves listed above which were assigned at PNPP to RHR Valve Groups 3 and 4. Because these other non–RCPB valves were assigned to Valve Groups 3 and 4, in addition to receiving Loss Of Coolant Accident (LOCA) isolation(s), they also receive an isolation from the Ambient Temperature instruments. Although some of these non-RCPB RHR system valves are not maintained closed by the high RPV pressure signal, the Ambient Temperature instruments providing Function 5.a are not required by the TS to be OPERABLE when RPV pressure is above the cut in permissive pressure. Although these non-RCPB RHR system valves do receive an isolation signal upon a high temperature, that is not the specified safety function of the Ambient Temperature portion of the Leak Detection System, since as described in Ref. 14, the Leak Detection System is designed to detect leakage from the RCPB, in piping which is in direct communication with the reactor vessel.

In MODES 4 and 5, high temperature leakage is not a concern, and significant water leakage is isolated by the Reactor Vessel Water Level - Low, Level 3 Function.

The Allowable Value is set low enough to detect a leak equivalent to 25 gpm.

This Function isolates the Group 3 and 4 valves.

5.b. Reactor Vessel Water Level-Low, Level 3

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.b. Reactor Vessel Water Level-Low, Level 3 (continued)

some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level-Low, Level 3 Function associated with RHR Shutdown Cooling System isolation is not directly assumed in any transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs. The RHR Shutdown Cooling System isolation on Level 3 supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event through the 1E12-F008 and 1E12-F009 valves caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System. The Reactor Vessel Water Level-Low, Level 3 channels required to be OPERABLE by Function 5.b are only those channels which are combined with the Reactor Vessel Pressure-High Function to provide isolation of the RHR Shutdown Cooling System suction from the reactor vessel (i.e., the 1E12-F008 and 1E12-F009 valves.)

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.b. Reactor Vessel Water Level-Low, Level 3 (continued)

Reactor Vessel Water Level – Low, Level 3 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level – Low, Level 3 Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level – Low, Level 3 Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level – Low, Level 3 Allowable Value (LCO 3.3.1.1) since the capability to cool the fuel may be threatened.

The Reactor Vessel Water Level – Low, Level 3 Function is required to be OPERABLE in MODES 2 and 3 when the reactor vessel steam dome pressure is less than the RHR cut in permissive pressure to prevent this potential flow path from lowering reactor vessel level to the top of the fuel. In MODE 1, and MODES 2 and 3 when the reactor vessel steam dome pressure is above the RHR cut in permissive pressure, the Reactor Steam Dome Pressure-High Function will maintain the RHR System isolated.

This Function isolates the Group 3 and 4 valves.

5.c. Reactor Vessel Steam Dome Pressure-High

The Reactor Vessel Steam Dome Pressure-High Function is provided to isolate the shutdown cooling portion of the RHR System. This interlock (RHR cut in permissive) is provided only for equipment protection to prevent an intersystem LOCA scenario and credit for the interlock is not assumed in the accident or transient analysis in the USAR.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.c. Reactor Vessel Steam Dome Pressure-High (continued)

The Reactor Vessel Steam Dome-High pressure signals are initiated from four transmitters. Four channels of Reactor Vessel Steam Dome Pressure-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Allowable Value was chosen to be low enough to protect the system equipment from overpressurization.

This Function isolates the Group 4 valves.

5.d. Drywell Pressure-High

High drywell pressure can indicate a break in the RCPB. The isolation of some of the PCIVs on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded (Ref. 8). The Drywell Pressure-High Function associated with isolation of the RHR System is not modeled in any USAR accident or transient analysis because other leakage paths (e.g., MSIVs) are more limiting.

High drywell pressure signals are initiated from four pressure transmitters that sense the pressure in the drywell. Four channels of Drywell Pressure-High Function are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure-High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 3 valves.

5.e. Manual Initiation

The Manual Initiation push button channels introduce signals into the RHR System isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific USAR safety analysis that takes credit for this Function. It is retained for the isolation function as required by the NRC in the plant licensing basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5.e. Manual Initiation (continued)

There are four push buttons for the logic, two manual initiation push buttons per trip system. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of the Manual Initiation Function are required to be OPERABLE.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 allows penetration path(s), with the exception of the drywell 24 inch and 36 inch purge supply and exhaust valve penetration flow paths and the inboard 42 inch primary containment purge supply and exhaust isolation valve flow paths, to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment or drywell isolation is indicated. Note 2 has been provided to modify the ACTIONS related to primary containment and drywell isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation and drywell instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, Note 2 has been provided that allows separate Condition entry for each inoperable primary containment and drywell isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function, has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. Functions that share common instrumentation with the RPS have a 12 hour allowed out of service time consistent with the time provided for the associated RPS instrumentation channels. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the

(continued)

ACTIONS

A.1 (continued)

tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in all automatic isolation capability being lost for the associated penetration flow path(s). A "Function" is a line item in Table 3.3.6.1-1, e.g., main steam line isolation from line item 1.a., "Reactor Vessel Water Level - Low Low Low, Level 1." The MSL isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that at least one automatic isolation valve in the associated penetration flow path(s) can receive an isolation signal from the given Function. Note that some penetrations only have a single automatic isolation valve or do not have redundant isolation channels, in which case the isolation capability is maintained if those single valves can receive an isolation signal from the given Function.

Also, some Functions consist of channels that monitor several different locations. Two examples are Function 1.c, Main Steam Line Flow - High, which needs to maintain the isolation capability for each of the four main steam lines, and Function 3.h, RHR Equipment Area Ambient Temperature - High, which needs to maintain the isolation capability based on monitoring ambient temperature in both RHR Equipment Areas #1 and #2. Condition B does not include the Manual Initiation Functions (Functions 1.h,

(continued)

ACTIONS

B.1 (continued)

2.h, 3.k, 4.l, and 5.e), since they are not assumed in any accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action A.1) is allowed.

It is important to note that when determining Technical Specification compliance for each specific associated trip system and channel, the Technical Specification Bases should not be the sole document referenced. Other source documents should be referenced-such as the Plant Data Book, plant procedures, and controlled mechanical and electrical schematic drawings.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 within 36 hours (Required Actions D.2.1 and D.2.2). Alternately, the associated MSLs may be isolated (Required Action D.1), and if allowed (i.e., plant safety analysis allows operation with an MSL isolated), plant operation with the MSL isolated may continue. Isolating the affected MSL accomplishes the safety function of the inoperable channel. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

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

F.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operation may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. Isolation may be achieved either by locking the affected isolation valve(s) in the closed position, or by verifying, by remote indication, that valve(s) are closed and electrically disarmed.

For some of the Ambient Temperature Functions, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A ambient temperature channel is inoperable, the RWCU pump room A area can be isolated while allowing continued RWCU operation utilizing RWCU pump B.

Alternatively, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken. The Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operation personnel to isolate the affected penetration flow path(s).

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s)

(continued)

BASES

ACTIONS

G.1 (continued)

accomplishes the safety function of the inoperable channels.

The 24 hour Completion Time is acceptable due to the fact that these Functions (Manual Initiation) are not assumed in any accident or transient analysis in the USAR. Alternately, if it is not desired to isolate the affected penetration flow path(s) (e.g., as in the case where isolating the penetration flow path(s) could result in a reactor scram), Condition H must be entered and its Required Actions taken.

H.1 and H.2

If the channel is not restored to OPERABLE status or placed in trip, or any Required Action of Condition F or G is not met and the associated Completion Time has expired, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 3 within 12 hours and in MODE 4 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.

I.1 and I.2

If the channel is not restored to OPERABLE status within the allowed Completion Time, the associated SLC subsystem(s) is declared inoperable or the RWCU System is isolated. Since this Function is required to ensure that the SLC System performs its intended function, sufficient remedial measures are provided by declaring the associated SLC subsystem inoperable or isolating the RWCU System.

The Completion Time of 1 hour is acceptable because it minimizes risk while allowing sufficient time for personnel to isolate the RWCU System.

(continued)

BASES

ACTIONS (continued)

J.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path should be isolated (e.g., close either 1E12-F008 or 1E12-F009). However, if the shutdown cooling function is needed to provide core cooling, these Required Actions allow the penetration flow path to remain unisolated provided action is immediately initiated to restore the channel to OPERABLE status. Actions must continue until the channel is restored to OPERABLE status.

(continued)

BASES

ACTIONS (continued)	K.1 and K.2 If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the associated penetration flow path(s) should be isolated (Required Action K.1). Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable instrumentation. Alternately, the plant must be placed in a condition in which the LCO does not apply. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe condition.
SURVEILLANCE REQUIREMENTS	As noted at the beginning of the SRs, the SRs for each Primary Containment and Drywell Isolation Instrumentation Function are found in the SRs column of Table 3.3.6.1-1. The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains primary containment isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

This Note is based on the reliability analysis (Refs. 5 and 6) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the automatic isolation valves will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.2 (continued)

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

For Function 1.e, "Main Steam Line Pipe Tunnel Temperature - High", this SR is applicable only to the Division 3 and 4 ambient temperature channels. Divisions 1 and 2 are monitored by digital instrument channels, which are functionally tested on semiannual basis by SR 3.3.6.1.7.

SR 3.3.6.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.6.1.4

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.6.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.5 (continued)

in LCO 3.6.1.3 and on drywell isolation valves in LCO 3.6.5.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.1.6

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. Testing is performed only on channels where the assumed response time does not correspond to the diesel generator (DG) start time. For channels assumed to respond within the DG start time, sufficient margin exists in the 10 second start time when compared to the typical channel response time (milliseconds) so as to assure adequate response without a specific measurement test. The instrument response times must be added to the PCIV closure times to obtain the ISOLATION SYSTEM RESPONSE TIME. ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in References 7 and 8. The Note to SR 3.3.6.1.6 states that channel sensors are excluded from response time testing requirements. Response time testing for the remaining channel components is required. This is supported by Reference 9.

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

SR 3.3.6.1.7

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1.7 (continued)

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

For Function 1.e, "Main Steam Line Pipe Tunnel Temperature High", this SR is applicable only to the Division 1 and 2 ambient temperature channels. Divisions 3 and 4 are monitored by analog instrument channels, which are functionally tested by SR 3.3.6.1.2.

REFERENCES

1. USAR, Section 6.3.
2. USAR, Chapter 15.
3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.
4. USAR, Section 9.3.5.
5. NEDC-31677-P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," June 1989.
6. NEDC-30851-P-A, Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
7. USAR, Section 15.1.3.
8. USAR, Section 15.6.
9. NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994.
10. Deleted.

(continued)

BASES

REFERENCES (continued)	11.	Deleted.
	12.	USAR, Section 15.7.6
	13.	Deleted.
	14.	USAR, Section 7.6.1.3

B 3.3 INSTRUMENTATION

B 3.3.6.2 Residual Heat Removal (RHR) Containment Spray System Instrumentation

BASES

BACKGROUND

The RHR Containment Spray System is an operating mode of the RHR System that is initiated to condense steam in the containment atmosphere. This ensures that containment pressure is maintained within its limits following a loss of coolant accident (LOCA). The RHR Containment Spray System can be initiated either automatically or manually.

The RHR Containment Spray System is automatically initiated by Reactor Vessel Water Level – Low Low Low, Level 1, Drywell Pressure – High, and Containment Pressure – High signals. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a signal which starts the system timer. The channels provide inputs to two trip systems; one trip system initiates one containment spray subsystem while the second trip system initiates the other containment spray subsystem (Ref. 1). For a trip system to initiate the associated subsystem, it must receive one signal from each of the following inputs: Drywell Pressure – High, Containment Pressure – High, and a System Timer. The Drywell Pressure – High and Containment Pressure – High Functions each have two channels per trip system, which are arranged in a one-out-of-two logic to provide the necessary signal. The System Timer is initiated by a one-out-of-two taken twice logic consisting of two channels each of the Reactor Vessel Water Level – Low Low Low, Level 1 and Drywell Pressure – High Functions. When the System Timer has timed out, the trip system receives the System Timer signal.

For the B trip system an additional timer of approximately 35 seconds is added to delay the actuation of the B subsystem. This is to avoid having both subsystems activate at the same time.

Manual initiation of the system is accomplished with the use of manual initiation push buttons. The system can be manually initiated using the manual initiation push buttons only if a Drywell Pressure – High signal is present.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Operation of the RHR Containment Spray System may be required to maintain containment pressure within design limits after a LOCA. Safety analyses in Reference 2 implicitly assume that sufficient instrumentation and controls, described below, are available to initiate the RHR Containment Spray System.

The RHR Containment Spray System instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the RHR Containment Spray System instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.2-1. Each Function must have the required number of OPERABLE channels with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments, as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

These uncertainties are described in the setpoint methodology.

The RHR Containment Spray System instrumentation is required to be OPERABLE in MODES 1, 2, and 3, when considerable energy exists in the Reactor Coolant System and a Design Basis Accident (DBA) could cause pressurization of the primary containment. In MODES 4 and 5, the reactor is shut down, and any LOCA would not cause pressurization of the drywell or containment.

The specific Applicable Safety Analyses and LCO discussions are listed below on a Function by Function basis.

1. Drywell Pressure – High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The RHR Containment Spray System mitigates the consequences of steam leaking from the drywell directly into containment airspace, bypassing the suppression pool.

Four Drywell Pressure – High transmitters (two per trip system) are required to be OPERABLE and capable of automatically initiating the RHR Containment Spray System. This ensures that no single instrument failure can preclude the RHR containment spray function. The Drywell Pressure – High Allowable Value is chosen to be the same as the Emergency Core Cooling Systems (ECCS) Drywell Pressure – High Allowable Value (LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation") since this could be indicative of a LOCA.

2. Containment Pressure – High

High pressure in the containment could indicate a break in the RCPB. The RHR Containment Spray System mitigates the consequences of steam leaking from the drywell directly into the containment airspace, bypassing the suppression pool.

Four Containment Pressure – High transmitters are available, but only two Containment Pressure – High transmitters (one per trip system) are required to be OPERABLE and capable of automatically initiating the RHR Containment Spray System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Containment Pressure - High (continued)

This ensures that no single instrument failure can preclude the RHR containment spray function.

The Containment Pressure - High Allowable Value is chosen to ensure the primary containment design pressure is not exceeded.

3. Reactor Vessel Water Level - Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that a break of the RCPB may have occurred and the capability to maintain the primary containment pressure within design limits may be threatened. The RHR Containment Spray System mitigates the consequences of the steam leaking from the drywell directly into the containment airspace, bypassing the suppression pool.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Low, Level 1 (two per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude the RHR containment spray function.

The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value (LCO 3.3.5.1) since this could be indicative of a LOCA.

4, 5. System A and System B Timers

The purpose of the System A and System B timers is to delay automatic initiation of the RHR Containment Spray System for approximately 10 minutes after low pressure coolant injection (LPCI) initiation to give the LPCI System time to fulfill its ECCS function in response to a LOCA. The time delay is needed since the RHR Containment Spray System utilizes the same pumps as the LPCI subsystem (RHR pumps).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4, 5. System A and System B Timers (continued)

There are two Function 4 timers, one for each subsystem, designated System A Timer and System B Timer. Since each subsystem of the RHR Containment Spray System has a timer, a single failure of a timer will cause the failure of only one RHR containment spray subsystem. The other subsystem will still be available to perform the RHR containment spray cooling function. The Allowable Value for the time delay is chosen to be long enough to allow the LPCI System to fulfill its function, but short enough to prevent containment pressure from exceeding the design limit.

In addition to the two Function 4 timers discussed above, subsystem B has an additional timer (Function 5) of approximately 35 seconds. This timer is included to prevent both containment spray subsystems from actuating at the same time. The Allowable Value for this time delay is chosen to be long enough for the operator to take action if containment spray subsystem A has already actuated to prevent subsystem B from also actuating, but short enough to prevent containment pressure from exceeding the design limit if subsystem A does not actuate.

6. Manual Initiation

The Manual Initiation Function introduces signals into the RHR containment spray logic and is redundant to all automatic protective instrumentation except Drywell Pressure—High. There is no specific USAR analysis that takes credit for this Function. It is retained for the initiation Function as required by the NRC approved licensing basis. Each trip system has a manual push button, for a total of two push buttons, both of which are required to be OPERABLE.

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR Containment Spray System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the

(continued)

BASES

ACTIONS (continued)

Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RHR Containment Spray System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR Containment Spray System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.6.2-1. The applicable Condition specified in the table is Function dependent. Each time a required channel is discovered inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RHR Containment Spray System. Automatic initiation capability is lost if one Function 1 channel in both trip systems is inoperable and untripped, or one Function 3 channel in both trip systems is inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate and both RHR containment spray subsystems, made inoperable by RHR Containment Spray System instrumentation, must be declared inoperable within 1 hour after discovery of loss of RHR Containment Spray System initiation capability for both trip systems.

The Completion Time 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." For Required Action B.1, the Completion Time only begins upon discovery that the RHR Containment Spray System cannot

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

be automatically initiated due to inoperable, untripped channels within the same Function, as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition, per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore the capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic initiation capability being lost for the RHR Containment Spray System. Automatic initiation capability is lost if two Function 2 channels or two Function 4 channels are inoperable. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and both of the associated RHR containment spray subsystems must be declared inoperable within 1 hour after discovery of loss of RHR Containment Spray System initiation capability for both trip systems. As noted, Required Action C.1 is only applicable for Functions 2 and 4. The Required Action is not applicable to Function 5 or 6 (which also require entry into this Condition if a channel in one of these Functions is inoperable). Function 5 does not have a corresponding channel in both subsystems. Function 6 is the Manual Initiation Function and is not

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

assumed in any USAR accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed.

The Completion Time 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." For Required Action C.1, the Completion Time only begins upon discovery that the RHR Containment Spray System cannot be automatically initiated due to two inoperable channels within the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the redundancy of sensors available to provide initiation signals, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action could either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1

With any Required Action and associated Completion Time of Condition B or C not met, the associated RHR containment spray subsystem may be incapable of performing the intended function and the RHR containment spray subsystem associated with inoperable untripped channels must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RHR Containment Spray System Function are located in the SRs column of Table 3.3.6.2-1.

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SURVEILLANCE REQUIREMENTS (continued)

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RHR containment spray initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RHR containment spray will initiate when necessary.

SR 3.3.6.2.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.6.2.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.6.2.4 and SR 3.3.6.2.6

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.3.6.2.5 The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.6.1.7, "Residual Heat Removal (RHR) Containment Spray," overlaps this Surveillance to provide complete testing of the assumed safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 7.3.1.1.4. 2. USAR, Section 6.2.1.1.5. 3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.6.3 Suppression Pool Makeup (SPMU) System Instrumentation

BASES

BACKGROUND

The SPMU System provides water from the upper containment pool to the suppression pool, by gravity flow, after a loss of coolant accident (LOCA) to ensure that primary containment temperature and pressure design limits are met. The SPMU System is automatically initiated by signals generated by Reactor Vessel Water Level – Low Low Low, Level 1; Drywell Pressure – High; and Suppression Pool Water Level – Low Low channels. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a signal to the trip logic. The channels provide inputs to two trip systems; one trip system initiates one SPMU subsystem while the second trip system initiates the other SPMU subsystem (Ref. 1). Two separate initiation logic are provided for each trip system.

One initiation logic for a trip system will initiate the associated subsystem if a LOCA signal coincident with a Suppression Pool Water Level – Low Low signal is received. The LOCA signal is received from the associated division of low pressure Emergency Core Cooling Systems (ECCS) initiation signal (i.e., two channels of Reactor Vessel Water Level – Low Low Low, Level 1 and two channels of Drywell Pressure – High are arranged in a one-out-of-two taken twice logic). Two channels of Suppression Pool Water Level – Low Low are arranged in a one-out-of-two logic, which generates the Suppression Pool Water Level – Low Low signal. The associated low pressure ECCS division's Manual Initiation push button (one per division) also supplies a signal, which manually performs the same function as the automatic LOCA signal (i.e., ECCS Manual Initiation coincident with a Suppression Pool Water Level – Low Low will initiate the trip system). Two SPMU Manual Initiation push buttons are also provided, which manually perform the same function as the automatic Suppression Pool Water Level – Low Low signal. The second initiation logic for a trip system will initiate the associated subsystem after a time delay of approximately 30 minutes after a LOCA signal is received.

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BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The SPMU System is relied upon to dump upper containment pool water to the suppression pool to maintain drywell horizontal vent coverage and an adequate suppression pool heat sink volume to ensure that the primary containment internal pressure and temperature stay within design limits (Ref. 2).

The SPMU System instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). Certain instrumentation Functions are retained for other reasons and are described in the individual Functions discussion.

The OPERABILITY of the SPMU System instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.6.3-1. Each Function must have the required number of OPERABLE channels with their setpoints within the specified Allowable Value, where appropriate. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Values between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal setpoint, but within the Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The SPMU System instrumentation is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the Reactor Coolant System and a DBA could cause pressurization and heatup of the primary containment. In MODES 4 and 5, the reactor is shut down; therefore, any LOCA would not cause pressurization of the drywell, and the SPMU System would not be needed to maintain suppression pool water level. Furthermore, in MODES 4 and 5, the SPMU System is not required since there is insufficient energy to heat up the suppression pool in the event of a LOCA.

The specific Applicable Safety Analyses and LCO discussions are listed below on a Function by Function basis.

1. Drywell Pressure-High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The Drywell Pressure-High is one of the Functions required to be OPERABLE and capable of initiating the SPMU System during the postulated accident. This protection is required to ensure primary containment temperature and pressure design limits are not exceeded during a LOCA. Accident analysis assumes that the horizontal vents remain covered during a LOCA. Therefore, this signal is used to dump water from the upper containment pool into the suppression pool as assumed in the large break LOCA analysis.

High drywell pressure signals are initiated from four pressure transmitters that sense the pressure at four different locations in the drywell. Four channels of Drywell Pressure- High Function (two channels per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude the SPMU System function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Drywell Pressure - High (continued)

The Allowable Value is chosen to be the same as the ECCS Drywell Pressure - High Allowable Value (LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation"), since this could be indicative of a LOCA.

2. Reactor Vessel Water Level - Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that a LOCA may have occurred and the capability to maintain the primary containment temperature and pressure and suppression pool level design limits may be threatened. Accident analysis assumes that the horizontal vents remain covered during a LOCA. Therefore, this signal is used to dump water from the upper containment pool into the suppression pool as assumed in the large break LOCA analysis.

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of reactor vessel water level (two channels per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude the SPMU System function. The Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value (LCO 3.3.5.1), since this could be indicative of a LOCA.

3. Suppression Pool Water Level - Low Low

The Suppression Pool Water Level - Low Low signal provides assurance that the water level in the suppression pool will not drop below that required to keep the horizontal vents covered for all LOCA break sizes. Accident analyses assume that the horizontal vents remain covered during a LOCA. Therefore, the signal indicating low suppression pool water level is used to dump water from the upper containment pool into the suppression pool as assumed in the large break LOCA analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

3. Suppression Pool Water Level - Low Low (continued)

Suppression pool water level signals are from four transmitters that sense pool level at four different locations (two per trip system). However, only two of the four Suppression Pool Water Level - Low Low channels (one per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude the SPMU System function due to the redundancy of the Function.

The Allowable Value is set high enough to ensure coverage of the horizontal vents.

4. Timer

The SPMU System valves open on a Drywell Pressure - High and/or Reactor Vessel Water Level - Low Low Low, Level 1 signal after approximately a 30 minute time delay, where the timer itself is started by these signals. The minimum suppression pool volume, without an upper pool dump, is adequate to meet all heat sink requirements for 30 minutes during a small break LOCA.

There are two SPMU System timers (one per trip system). Two timers are required to be OPERABLE to ensure that no single timer failure can preclude the SPMU System function. The Allowable Value is chosen to be short enough to ensure that the suppression pool will serve as an adequate heat sink during a small break LOCA.

5. Manual Initiation

The SPMU System Manual Initiation push button channels produce signals to provide manual initiation capabilities that are redundant to the automatic protective instrumentation. The Manual Initiation Function is not assumed in any transient or accident analysis in the USAR. However, the Function is retained for overall redundancy and diversity of the SPMU System as required by the NRC in the approved licensing basis.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Manual Initiation (continued)

Two manual initiation push buttons (one per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude the SPMU System function. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

ACTIONS

A Note has been provided to modify the ACTIONS related to SPMU System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable SPMU System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable SPMU System instrumentation channel.

A.1

Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.6.3-1. The applicable Condition specified in the Table is Function dependent. Each time a required channel is discovered inoperable, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Required Action B.1 is intended to ensure appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the SPMU System. In this case, automatic initiation capability is lost if (a) one Function 1 channel in both trip systems is inoperable and untripped, or (b) one Function 2 channel in

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

both trip systems is inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate and both SPMU subsystems must be declared inoperable within 1 hour after discovery of loss of SPMU initiation capability for both trip systems.

The Completion Time 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." For Required Action B.1, the Completion Time only begins upon discovery that the SPMU System cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the SPMU System. In this case, automatic initiation capability is lost if two required Function 3 channels or two Function 4 channels are

(continued)

ACTIONS

C.1 and C.2 (continued)

inoperable. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action C.2 is not appropriate and the SPMU System must be declared inoperable within 1 hour after discovery of loss of SPMU initiation capability for both trip systems. As noted, Required Action C.1 is only applicable for Functions 3 and 4. Required Action C.1 is not applicable to Function 5 (which also requires entry into this Condition if a channel in this Function is inoperable), since it is the Manual Initiation Function and is not assumed in any USAR accident or transient analysis. Thus, a total loss of manual initiation capability for 24 hours (as allowed by Required Action C.2) is allowed.

The Completion Time 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." For Required Action C.1, the Completion Time only begins upon discovery that the SPMU System cannot be automatically initiated due to two inoperable channels within the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the redundancy of sensors available to provide initiation signals, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition D must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action could either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1

With any Required Action and associated Completion Time of Condition B or C not met, the associated SPMU subsystem may be incapable of performing the intended function and the SPMU subsystem associated with inoperable, untripped channels must be declared inoperable immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each SPMU System Function are located in the SRs column of Table 3.3.6.3-1.

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains suppression pool makeup initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the SPMU will initiate when necessary.

SR 3.3.6.3.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of the LCO.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.6.3.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.3-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.6.3.4 and SR 3.3.6.3.5

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.3.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.6.2.4, "Suppression Pool Makeup (SPMU) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

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

REFERENCES

1. USAR, Section 7.3.1.1.12.

2. USAR, Section 6.2.7.

3. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.6.4 Relief and Low-Low Set (LLS) Instrumentation

BASES

BACKGROUND

The safety/relief valves (S/RVs) prevent overpressurization of the nuclear steam system. Instrumentation is provided to support two modes of S/RV operation—the relief function (all valves) and the LLS function (selected valves). Refer to LCO 3.4.4, "Safety/Relief Valves (S/RVs)," and LCO 3.6.1.6, "Low-Low Set (LLS) Safety/Relief Valves (S/RVs)," Applicability Bases for additional information on these modes of S/RV operation.

The relief function of the S/RVs prevents overpressurization of the nuclear steam system. The LLS function of the S/RVs is designed to mitigate the effects of postulated pressure loads on the containment by preventing multiple actuations in rapid succession of the S/RVs subsequent to their initial actuation.

Upon any S/RV actuation, the LLS logic assigns preset opening and reclosing setpoints to six preselected S/RVs. These setpoints are selected to override the normal relief setpoints such that the LLS S/RVs will stay open longer, thus releasing more steam (energy) to the suppression pool; hence more energy (and time) is required for repressurization and subsequent S/RV openings. The LLS logic increases the time between (or prevents) subsequent S/RV actuations to limit these actuations to one valve, so that containment loads will also be reduced.

The relief instrumentation consists of two trip systems, with each trip system actuating one solenoid for each S/RV. There are two solenoids per S/RV, and each solenoid can open its respective S/RV. The relief mode (S/RVs and associated trip systems) is divided into three setpoint groups (the low with one S/RV, the medium with nine S/RVs, and the high with nine S/RVs). The S/RV relief function is actuated by transmitters that monitor reactor steam dome pressure. The reactor steam dome pressure transmitters send signals to trip units whose outputs are arranged in a two-out-of-two logic for each trip system in each of three separate setpoint groups (e.g., the medium group of nine S/RVs opens when at least one of the associated trip systems trips at

(continued)

BACKGROUND (continued)

its assigned setpoint). Once an S/RV has been opened, it will reclose when reactor steam dome pressure decreases below the opening pressure setpoint. This logic arrangement ensures that no single instrument failure can preclude the S/RV relief function.

The LLS logic consists of two trip systems similar to the S/RV relief function. Either trip system can actuate the LLS S/RVs by energizing the associated S/RV solenoid. Each LLS trip system is enabled and sealed in upon initial S/RV actuation from the existing reactor vessel steam dome pressure sensors of any of the normal relief setpoint groups. The reactor steam dome pressure channels used to arm LLS are arranged in a one- out-of-three taken twice logic. The reactor steam dome pressure channels that control the opening and closing of the LLS S/RVs are arranged in a two-out-of-two logic. This logic arrangement ensures that no single instrument failure can preclude the LLS S/RV function. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LLS or relief initiation signal, as applicable, to the initiation logic.

APPLICABLE SAFETY ANALYSES

The relief and LLS instrumentation are designed to prevent overpressurization of the nuclear steam system and to ensure that the containment loads remain within the primary containment design basis (Ref. 1).

Relief and LLS instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The LCO requires OPERABILITY of sufficient relief and LLS instrumentation channels to provide adequate assurance of successfully accomplishing the relief and LLS function, assuming any single instrumentation channel failure within the LLS logic. Therefore, two trip systems are required to be OPERABLE. The OPERABILITY of each trip system is dependent upon the OPERABILITY of the reactor steam dome pressure channels associated with required relief and LLS S/RVs. Each required channel shall have its setpoint within the specified Allowable Value. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

(continued)

BASES

LCO (continued)

Allowable Values are specified for each channel in SR 3.3.6.4.3. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel pressure), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

For relief, the actuating Allowable Values are based on the transient event of main steam isolation valve (MSIV) closure with an indirect scram (i.e., neutron flux). This analysis is described in Reference 1. For LLS, the actuating and reclosing Allowable Values are based on the transient event of MSIV closure with a direct scram (i.e., MSIV position switches). This analysis is also described in Reference 1.

APPLICABILITY

The relief and LLS instrumentation is required to be OPERABLE in MODES 1, 2, and 3, since considerable energy exists in the nuclear steam system and the S/RVs may be needed to provide pressure relief. If the S/RVs are needed, then the relief and LLS functions are required to ensure that the primary containment design basis is maintained. In MODES 4 and 5, the reactor pressure is low enough that the overpressure limit cannot be approached by assumed operational transients or accidents. Thus, relief and LLS instrumentation are not required.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

Because the failure of any reactor vessel steam dome pressure instrument channels in one trip system will not prevent the associated S/RV from performing its relief and LLS functions, 7 days is allowed to restore a trip system to OPERABLE status (Required Action A.1). In this condition, the remaining OPERABLE trip system is adequate to perform the relief and LLS initiation functions. However, the overall reliability is reduced because a single failure in the OPERABLE trip system could result in a loss of relief or LLS function.

Alternatively, declaring the associated relief and LLS valve(s) inoperable (Required Action A.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.4.4 and LCO 3.6.1.6) provide appropriate actions for the inoperable components.

The 7 day Completion Time is considered appropriate for the relief and LLS function because of the redundancy of sensors available to provide initiation signals and the redundancy of the relief and LLS design. In addition, the probability of multiple relief or LLS instrumentation channel failures, which renders the remaining trip system inoperable, occurring together with an event requiring the relief or LLS function during the 7 day Completion Time is very low.

B.1 and B.2

If the Required Action and associated Completion Time is not met or if two trip systems are inoperable, 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 12 hours and to MODE 4 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 Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to

(continued)

SURVEILLANCE REQUIREMENTS (continued)

6 hours, provided the associated Function maintains relief or LLS initiation capability, as applicable. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel surveillance. That analysis demonstrated the 6 hour testing allowance does not significantly reduce the probability that the relief and LLS valves will initiate when necessary.

SR 3.3.6.4.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.6.4.2

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.6.4.3. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.4.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.6.4.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed for S/RVs in LCO 3.4.4 and LCO 3.6.1.6 overlaps this Surveillance to provide complete testing of the assumed safety function.

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

REFERENCES

1. USAR, Section 5.2.2.

2. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Recirculation (CRER) System Instrumentation

BASES

BACKGROUND

The CRER System is designed to provide a radiologically controlled environment to ensure the habitability of the control room for the safety of control room operators under all plant conditions. Two independent CRER subsystems are each capable of fulfilling the stated safety function. The instrumentation and controls for the CRER System automatically initiate action to isolate the main control room to minimize the consequences of radioactive material in the control room environment.

In the event of a Reactor Vessel Water Level-Low Low Low, Level 1, Drywell Pressure-High, or Control Room Ventilation Radiation Monitor signal, the CRER System is automatically started in the emergency recirculation mode. The control room air is then recirculated through the charcoal filter to reduce the concentration of airborne radioactive contaminants.

The CRER System instrumentation has two trip systems: one trip system initiates one CRER subsystem, while the second trip system initiates the other CRER subsystem (Ref. 1). Each trip system receives input from the Functions listed above. The Functions are arranged as follows for each trip system. The Reactor Vessel Water Level-Low Low Low, Level 1 and Drywell Pressure-High are arranged together in a one-out-of-two taken twice logic. The Control Room Ventilation Radiation Monitor is arranged in a one-out-of-one logic. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a CRER System initiation signal to the initiation logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CRER System to maintain the habitability of the control room is explicitly assumed for certain accidents as discussed in the USAR safety analyses (Refs. 2 and 3). CRER System operation ensures that the radiation exposure of control room personnel, through the duration of any one of the postulated accidents, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A.

(continued)

BASES

APPLICABLE LCO, and APPLICABILITY (continued)

CRER System instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

The OPERABILITY of the CRER System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each CRER System Instrumentation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. These nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint that is less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1. Reactor Vessel Water Level - Low Low Low, Level 1

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. A low reactor vessel water level could indicate a LOCA, and will automatically initiate the CRER System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

Reactor Vessel Water Level – Low Low Low, Level 1 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level – Low Low Low, Level 1 Function (two channels per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude CRER System initiation. The Allowable Value for the Reactor Vessel Water Level - Low Low Low, Level 1 is chosen to be the same as the Reactor Vessel Water Level - Low Low Low, Level 1 Allowable Value (LCO 3.3.5.1, “ECCS Instrumentation”).

The Reactor Vessel Water Level - Low Low Low, Level 1 Function is required to be OPERABLE in MODES 1, 2, and 3, to ensure that the control room personnel are protected. In MODES 4 and 5, the Control Room Ventilation Radiation Monitor Function provides adequate protection.

2. Drywell Pressure - High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). A high drywell pressure signal could indicate a LOCA and will automatically initiate the CRER System, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Drywell Pressure – High (continued)

Drywell Pressure - High signals are initiated from four pressure transmitters that sense drywell pressure. Four channels of Drywell Pressure - High Function (two channels per trip system) are required to be OPERABLE to ensure that no single instrument failure can preclude CRER System initiation.

The Drywell Pressure - High Allowable Value was chosen to be the same as the ECCS Drywell Pressure - High Allowable Value (LCO 3.3.5.1).

The Drywell Pressure - High Function is required to be OPERABLE in MODES 1, 2, and 3 to ensure that control room personnel are protected during a LOCA. In MODES 4 and 5, the Drywell Pressure - High Function is not required since there is insufficient energy in the reactor to pressurize the drywell to the Drywell Pressure - High setpoint.

3. Control Room Ventilation Radiation Monitor

The Control Room Ventilation Radiation Monitor measures radiation levels downstream of the supply plenum discharge of the control room. A high radiation level may pose a threat to control room personnel; thus, the Control Room Ventilation Radiation Monitor Function will automatically initiate the CRER System.

The Control Room Ventilation Radiation Monitor Function consists of one noble gas monitor. One channel (which provides input to both Trip Systems) of the Control Room Ventilation Radiation Monitor is required to be OPERABLE. Since a LOCA signal will also initiate the CRER System isolating the control room from the environment, and considering the fact that a LOCA signal itself incorporates sufficient redundancy, the airborne radiation monitor signal is considered a diverse signal, and does not require redundancy. The Allowable Value was selected to ensure protection of the control room personnel.

The Control Room Ventilation Radiation Monitor Function is required to be OPERABLE in MODES 1, 2, and 3, and during movement of recently irradiated fuel in the primary containment or Fuel Handling Building to ensure

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	<u>3. Control Room Ventilation Radiation Monitors</u> (continued) that control room personnel are protected during a LOCA or a fuel handling event involving recently irradiated fuel. Due to radioactive decay, handling of fuel only requires OPERABILITY of this Function when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 9). During MODES 4 and 5, when the specified condition (i.e., movement of recently irradiated fuel assemblies) is not in progress, the probability of a LOCA or significant fuel damage is low; thus, the Function is not required.
ACTIONS	A Note has been provided to modify the ACTIONS related to CRER System instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable CRER System instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable CRER System instrumentation channel. <u>A.1</u> Required Action A.1 directs entry into the appropriate Condition referenced in Table 3.3.7.1-1. The applicable Condition specified in the Table is Function dependent.

(continued)

BASES

ACTIONS

A.1 (continued)

Each time an inoperable channel is discovered, Condition A is entered for that channel and provides for transfer to the appropriate subsequent Condition.

B.1 and B.2

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CRER System design, an allowable out of service time of 24 hours has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable

(continued)

ACTIONS

B.1 and B.2 (continued)

provided the associated Function is still maintaining CRER System initiation capability. A Function is considered to be maintaining CRER System initiation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate an initiation signal from the given Function on a valid signal. This would require one trip system to have two channels, each OPERABLE or in trip. In this situation (loss of CRER System initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate. If the Function is not maintaining CRER System initiation capability, both CRER subsystems must be declared inoperable within 1 hour of discovery of loss of CRER System initiation capability in both trip systems. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition D must be entered and its Required Actions taken.

C.1 and C.2

The control room ventilation radiation monitor signal is considered a diverse signal from the redundant Drywell Pressure-High, and Reactor Vessel Water Level-Low Low Low, Level 1 signals. Because of this, the control room ventilation radiation monitor is not required to be redundant. Therefore, a Completion Time of 7 days is provided to permit restoration of the inoperable channel to OPERABLE status as long as an alternate means of monitoring the control room atmosphere for radiation has been established in the first 24 hours. Acceptable alternate means include a portable continuous noble gas monitor or the control room area radiation monitor. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, Condition D must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Completion Times associated with this Condition are based on the consideration that this Function provides a diverse signal from the LOCA signals, and on engineering judgement.

D.1 and D.2

With any Required Action and associated Completion Time of Condition B or C not met, the associated CRER subsystem must be placed in the emergency recirculation mode of operation (Required Action D.1) to ensure that control room personnel will be protected in the event of a Design Basis Accident. The method used to place the CRER subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the CRER subsystem(s). Alternately, if it is not desired to start the subsystem, the CRER subsystem associated with inoperable, untripped channels must be declared inoperable within 1 hour.

The 1 hour Completion Time is intended to allow the operator time to place the CRER subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels, or for placing the associated CRER subsystem in operation.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each CRER System Instrumentation Function are located in the SRs column of Table 3.3.7.1-1.

The Surveillances are also modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains CRER System initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 4, 5, and 6) assumption of the average time required

(continued)

SURVEILLANCE REQUIREMENTS (continued)

to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the CRER System will initiate when necessary.

SR 3.3.7.1.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the indicated parameter for one instrument 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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.1.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.7.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

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

SR 3.3.7.1.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.7.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.3, "Control Room Emergency Recirculation (CRER) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

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

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 7.3.1.1.7.
2. USAR, Section 6.4.
3. USAR, Chapter 15.
4. GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," February 1991.
5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
6. NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
7. Deleted.
8. Deleted.
9. USAR, Section 15.7.6

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND	Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources. The Loss of Voltage and Degraded Voltage Functions are common to Divisions 1, 2, and 3. The voltage for the Division 1, 2, and 3 buses is monitored at two levels, which can be considered as two different undervoltage functions: loss of voltage and degraded voltage. The LOP instrumentation comprises two Functions for Divisions 1, 2, and 3, which represent different voltage levels that cause various bus transfers and disconnects (Ref. 1). The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The LOP instrumentation is required for the Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs provide plant protection in the event of any of the analyzed accidents in References 2, 3, and 4 in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP instrumentation satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoint does not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

4.16 kV Emergency Bus Undervoltage

1.a, 1.b. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude the DG function. A channel is defined as a voltage sensing coil. Refer to LCO 3.8.1, "AC Sources - Operating" for Applicability Bases for the DGs.

1.c, 1.d, 1.e. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that while offsite power may not be completely lost to the respective emergency bus, power may be insufficient for starting large motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.c, 1.d, 1.e. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated emergency bus are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude the DG function. A channel is defined as a voltage sensing coil. Refer to LCO 3.8.1 for Applicability Bases for the DGs.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more channels of a Function inoperable, the Function may not be capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable

(continued)

BASES

ACTIONS

A.1 (continued)

channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1

If the Required Action and associated Completion Time is not met, the associated Function may not be capable of performing the intended function. Therefore, the associated DG(s) are declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1, which provides appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.1

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 instrument channels could be an indication of excessive instrument drift in one of the channels or 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 plant 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 instrument has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of the LCO.

SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic upon the receipt of actuation signals. The system functional testing performed in LCO 3.8.1 overlaps this Surveillance to provide complete testing of the assumed safety functions.

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

REFERENCES

1. USAR, Section 8.3.1.1.2.9.a.2.
2. USAR, Section 5.2.
3. USAR, Section 6.3.
4. USAR, Chapter 15.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

The RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against abnormal voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path for the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and various valve isolation logic.

The RPS Electric Power Monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supplies and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both in-series electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions, such as an unregulated power supply, can cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram solenoids, as well as the main steam isolation valve solenoids, may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these

(continued)

BASES

BACKGROUND (continued)

circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the MG set exceeds the predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

APPLICABLE SAFETY ANALYSES

RPS electric power monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS electric power monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by disconnecting the RPS from the power supply under specified conditions that could damage the RPS bus powered equipment.

RPS electric power monitoring satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The OPERABILITY of each RPS electric power monitoring assembly is dependent upon the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS bus powered components. Each inservice electric power monitoring assembly's trip logic setpoints are required to be within the specific Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less

(continued)

BASES

LCO (continued)

conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined, accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

The Allowable Values for the instrument settings are based on the RPS providing ≥ 57 Hz, 120 V ± 10% (to all equipment), and 115 V ± 10 V (to scram and MSIV solenoids). The most limiting voltage requirement and associated line losses determine the settings of the electric power monitoring instrument channels. The settings are calculated based on the loads on the buses and RPS MG set or alternate power supply being 120 VAC and 60 Hz.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS bus powered components from the MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a non-class 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1, 2, and 3, and MODES 4 and 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies or the Residual Heat Removal (RHR) Shutdown Cooling System not isolated.

(continued)

BASES (continued)

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus powered components during abnormal voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System are reduced and only a limited time (72 hours) is allowed to restore the inoperable assembly(s) to OPERABLE status. If the inoperable assembly(s) cannot be restored to OPERABLE status, the associated power supply must be removed from service (Required Action A.1). This places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly and the low probability of an event requiring RPS Electric Power Monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternatively, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable, or both power monitoring assemblies in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supplies must be removed from service within 1 hour (Required Action B.1). An alternate power supply with

(continued)

BASES

ACTIONS

B.1 (continued)

OPERABLE assemblies may then be used to power one RPS bus. The 1 hour Completion Time is sufficient for the plant operations personnel to take corrective actions and is acceptable because it minimizes risk while allowing time for restoration or removal from service of the electric power monitoring assemblies.

Alternately, if it is not desired to remove the power supply(s) from service (e.g., as in the case where removing the power supply(s) from service would result in a scram or isolation), Condition C or D, as applicable, must be entered and its Required Actions taken.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 1, 2, or 3, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 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.

D.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5, with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. This Required Action results in the least reactive condition for the reactor core and ensures that the safety function of the RPS (e.g., scram of control rods) is not required.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5, with the RHR Shutdown Cooling System not isolated, the operator must immediately initiate action to isolate the RHR Shutdown Cooling System (i.e., provide alternate decay heat removal capabilities so the penetration flow path can be isolated).

Alternately, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action E.2). Required Action E.2 is provided because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.1

A CHANNEL FUNCTIONAL TEST is performed on each overvoltage, undervoltage, and underfrequency channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted in the Surveillance, the CHANNEL FUNCTIONAL TEST is only required to be performed while the plant is in a condition in which the loss of the RPS bus will not jeopardize steady state power operation (the design of the system is such that the power source must be removed from service to conduct the Surveillance). The 24 hours is intended to indicate an outage of sufficient duration to allow for scheduling and proper performance of the Surveillance. The Note in the Surveillance is based on guidance provided in Generic Letter 91-09 (Ref. 2). This surveillance can be performed under other plant conditions provided that the risk is evaluated pursuant to 10 CFR 50.65(a)(4) (Ref. 3). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2.2

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2.2 (continued)

successive calibrations consistent with the plant specific setpoint methodology.

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

SR 3.3.8.2.3

Performance of a system functional test demonstrates a required system actuation (simulated or actual) signal. The logic of the system will automatically trip open the associated power monitoring assembly circuit breaker. Only one signal per power monitoring assembly is required to be tested. This Surveillance overlaps with the CHANNEL CALIBRATION to provide complete testing of the safety function. The system functional test of the Class 1E circuit breakers is included as part of this test to provide complete testing of the safety function. If the breakers are incapable of operating, the associated electric power monitoring assembly would be inoperable.

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

REFERENCES

1. USAR, Section 8.3.1.1.5.
2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electric Protective Assemblies in Power Supplies for the Reactor Protection System."
3. 10 CFR 50.65(a)(4), ''Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.''

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Coolant Recirculation System is designed to provide a forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes more heat from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The Reactor Coolant Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains a two speed motor driven recirculation pump, a flow control valve and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

(continued)

BASES

BACKGROUND (continued)

The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a wide range of power generation (i.e., 55 to 100% RTP) without having to move control rods and disturb desirable flux patterns.

Each recirculation loop is manually started from the control room. The recirculation flow control valves provide regulation of individual recirculation loop drive flows. The flow in each loop can be manually or automatically controlled. During single recirculation loop operation, the recirculation flow control system is maintained in the Loop Manual mode. If the recirculation flow control system is not in the Loop Manual mode while in single recirculation loop operation, immediately initiate action to place the recirculation flow control system in the Loop Manual mode within one hour.

During single recirculation loop operation, with the volumetric recirculation loop drive flow greater than 48,500 gpm, immediately initiate action to reduce flow to less than or equal to 48,500 gpm within one hour.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Coolant Recirculation System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgement.

The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during anticipated operational occurrences (AOOs) (Ref. 2), which are analyzed in Chapter 15 of the USAR.

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided THERMAL POWER is reduced to ≤ 2500 MWt, and the APLHGR and LHGR requirements are modified accordingly (Ref. 3).

The transient analyses of Chapter 15 of the USAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided THERMAL POWER is reduced to ≤ 2500 MWt, and the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System average power range monitor (APRM) instrument setpoints is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR, LHGR and MCPR limits for single loop operation are specified in the COLR. The APRM flow biased simulated thermal power setpoint is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

Recirculation loops operating satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

Two recirculation loops are normally required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternatively, with the limits specified in SR 3.4.1.1 not met, the recirculation loop with the lower flow must be considered to be not in operation. With only one recirculation loop in operation, THERMAL POWER must be ≤ 2500 MWt, and modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), and APRM Flow Biased Simulated Thermal Power-High setpoint (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of Reference 3.

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

(continued)

BASES

APPLICABILITY (continued)	In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

With both recirculation loops operating but the recirculation loop flows not matched, Required Action A.1 requires that the recirculation loops must be restored to operation with matched flows within 2 hours. If the flow mismatch can not be restored to within limits within 2 hours, one recirculation loop must be declared to be "not in operation".

A recirculation loop is considered to be not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits. The loop with the lower flow must be considered not in operation. Should a LOCA or AOO occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA or AOO analyses. Therefore, only a limited time is allowed to restore the inoperable loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to operating limits and RPS setpoints, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident or AOO sequence.

The 2 hour Completion Time is based on the low probability of an accident or AOO occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If large mismatches are detected, the condition should be alleviated by changing flow control valve position to re-establish forward flow or by tripping the pump, per plant procedures.

(continued)

BASES

ACTIONS (continued)

B.1

Should a LOCA or AOO occur with THERMAL POWER > 2500 MWt during single loop operation, the core response may not be bounded by the safety analyses. Therefore, only a limited time is allowed to reduce THERMAL POWER to ≤ 2500 MWt.

The 1 hour Completion Time is based on the low probability of an accident or AOO occurring during this time period, on a reasonable time to complete the Required Action, and on frequent core monitoring by operators allowing changes in THERMAL POWER to be quickly detected.

(continued)

BASES

ACTIONS (continued)

C.1

If the required limit and setpoint modifications for single recirculation loop operation are not performed within 24 hours after transition from two recirculation loop operation to single recirculation loop operation, or requirements b.2, b.3, b.4 or b.5 of the LCO are not met for some other reason, the unit must be brought to a MODE in which the LCO does not apply (see Condition D). The 24 hour Completion Time of the Condition provides time before the required modifications to required limits and setpoints have to be in effect after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. This time is provided due to the need to stabilize operation with one recirculation loop, including the procedural steps necessary to limit flow and adjust the flow control mode (to only Loop Manual mode) in the operating loop, and the complexity and detail required to fully implement and confirm the required limit and setpoint modifications. The 24 hour Completion Time is also based on the low probability of an accident or AOO occurring during this period, on a reasonable time to complete the Required Action, and on frequent monitoring by operators allowing abrupt changes in core flow conditions to be quickly detected.

D.1

With no recirculation loops in operation, or the Required Action and associated Completion Time of Conditions A, B, or C not met, the unit is required to be brought to a MODE in which the LCO does not apply. The plant is required to be placed in MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loop flows are within the allowable limits for mismatch. At low core flow (i.e., < 70% of rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. The recirculation loop jet pump flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop.

The mismatch is measured in terms of percent of rated core flow. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.3.3.7.2.
2. USAR, Section 5.4.1.1.
3. USAR, Chapter 15, Appendix 15F.
4. NRC Bulletin 88-07, Supplement 1, "Power Oscillations in Boiling Water Reactors," December 1988.
5. GE Letter, "Interim Recommendations for Stability Actions," November 1988.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Flow Control Valves (FCVs)

BASES

BACKGROUND

The Reactor Coolant Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how this affects the design basis transient and accident analyses. The jet pumps and the FCVs are part of the Reactor Coolant Recirculation System. The jet pumps are described in the Bases for LCO 3.4.3, "Jet Pumps."

The Recirculation Flow Control System consists of the electronic and hydraulic components necessary for the positioning of the two hydraulically actuated FCVs. The recirculation loop flow rate can be rapidly changed within the expected flow range, in response to rapid changes in system demand. Limits on the system response are required to minimize the impact on core flow response during certain accidents and transients. Solid state control logic will generate an FCV "motion inhibit" signal in response to any one of several hydraulic power unit or analog control circuit failure signals. The "motion inhibit" signal causes hydraulic power unit shutdown and hydraulic isolation such that the FCVs fail "as is."

APPLICABLE SAFETY ANALYSES

The FCV stroke rate is limited to ≤ 11% per second in the opening and closing directions on a control signal failure of maximum demand. This stroke rate is an assumption of the analysis of the recirculation flow control failures on decreasing and increasing flow (Refs. 1 and 2).

Flow control valves satisfy Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

An FCV in each operating recirculation loop must be OPERABLE to ensure that the assumptions of the design basis transient and accident analyses are satisfied.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the FCVs are required to be OPERABLE, since during these conditions there is considerable energy in the reactor core, and the limiting design basis transients and accidents are assumed to occur. In MODES 3, 4, and 5, the consequences of a transient or accident are reduced and OPERABILITY of the flow control valves is not important.

ACTIONS

A Note has been provided to modify the ACTIONS related to FCVs. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable FCVs provide appropriate compensatory measures for separate inoperable FCVs. As such, a Note has been provided that allows separate Condition entry for each inoperable FCV.

A.1

With one or two required FCVs inoperable, the assumptions of the design basis transient and accident analyses may not be met and the inoperable FCV must be returned to OPERABLE status or hydraulically locked within 4 hours.

Opening an FCV faster than the limit could result in a more severe flow runout transient, resulting in violation of the MCPR Safety Limit. Closing an FCV faster than the limit assumed in the LOCA analysis could affect the recirculation flow coastdown, resulting in higher peak clad temperatures. Therefore, if an FCV is inoperable due to stroke times faster than the limits, deactivating the FCV (locked up) will essentially lock the FCV in position, which will prohibit the FCV from adversely affecting the DBA and transient analyses. Continued operation is allowed in this Condition.

The 4 hour Completion Time is a reasonable time period to complete the Required Action, while limiting the time of operation with an inoperable FCV.

(continued)

BASES

ACTIONS (continued)

B.1

If the FCV(s) are not deactivated (locked up) and cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours. This brings the unit to a condition where the flow coastdown characteristics of the recirculation loop are not important. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

Hydraulic power unit pilot operated lock out valves (pilot operated check valves) located between the flow control valve (FCV) actuator and the pilot operated isolation valves (POIV) are required to close on a loss of hydraulic pressure. When closed, these valves inhibit FCV motion by blocking hydraulic pressure from the POIV valve to the FCV actuator. This surveillance verifies the FCV fails "as-is" on a loss of hydraulic pressure.

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

SR 3.4.2.2

This SR ensures the overall average rate of FCV movement at all positions is maintained within the analyzed limits.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.2.2 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.3.2. 2. USAR, Section 15.4.5.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Jet Pumps

BASES

BACKGROUND	The Reactor Coolant Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses. The jet pumps are part of the Reactor Coolant Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two thirds core height, the vessel can be reflooded and coolant level maintained at two thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation. Each reactor coolant recirculation loop contains 10 jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.
APPLICABLE SAFETY ANALYSES	Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA. Jet pumps satisfy Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Coolant Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).
APPLICABILITY	In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Coolant Recirculation System (LCO 3.4.1). In MODES 3, 4, and 5, the Reactor Coolant Recirculation System is not required to be in operation, and when not in operation sufficient flow is not available to evaluate jet pump OPERABILITY.
ACTIONS	A.1 An inoperable jet pump can increase the blowdown area and reduce the capability of reflooding during a design basis LOCA. If one or more of the jet pumps are inoperable, 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3). Since refueling activities (e.g.,fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Jet pump OPERABILITY is considered acceptable prior to startup of the plant following a refueling outage due to acceptable results obtained during the last cycle, or by visual inspection of the jet pumps. Similarly, initial entry into extended single loop recirculation loop operation may also require establishment of these relationships. During the initial weeks of OPERATING under such circumstances, while baselining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design basis accident, increase the blowdown area and reduce the capability of reflooding the core. Thus, the requirement for shutdown of the plant exists with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation. During single loop operation, the jet pump OPERABILITY surveillance is only performed for the jet pumps on the operating recirculation loop, as the loads on the jet pumps on the inactive loop have been demonstrated through operating experience at

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

other BWRs to be very low due to the low flow in the reverse direction through them. The jet pumps in the non-operating recirculation loop during single loop operation (SLO) are considered OPERABLE based on this low expected loading, acceptable surveillance results obtained during two recirculation loop operation prior to entering SLO, or by visual inspection of the jet pumps during outages. Upon startup of an idle recirculation loop when THERMAL POWER is greater than 25% of RATED THERMAL POWER, the specified jet pump surveillances are required to be performed for the previous idle loop within four hours as specified in SR 3.4.3.1.

The recirculation flow control valve (FCV) operating characteristics (loop flow versus FCV position) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a flow restriction, loss in pump hydraulic performance, leak, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the loop flow versus FCV position relationship must be verified.

Total core flow can be determined from measurements of the recirculation loop drive flows. Once this relationship has been established, increased or reduced recirculation loop drive flow for the same total core flow may be an indication of failures in one or several jet pumps.

Recirculation loop drive flow is the discharge flow from the recirculation pumps. Recirculation loop jet pump flow is the summation of all the individual jet pump flows for a particular recirculation loop. Total core flow for two recirculation loop operation is the sum of the recirculation loop jet pump flows for both loops. Total core flow for single recirculation loop operation is the recirculation loop jet pump flow for the operating loop minus the reverse flow through the non-operating loop. Rated core flow as used in the Specification corresponds to the rated (100%) core flow value for two recirculation loop operation (i.e., 104 Mlb/hr).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

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

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed when THERMAL POWER is ≤ 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

REFERENCES

1. USAR, Section 6.3.
2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1990.
3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) requires the Reactor Pressure Vessel be protected from overpressure during upset conditions by self actuated safety valves. As part of the nuclear pressure relief system, the size and number of safety/relief valves (S/RVs) are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. Each S/RV discharges steam through a discharge line and quencher to a location below the minimum water level in the suppression pool. With one or more S/RVs stuck open, operators will close the S/RV, thus minimizing the increase in suppression pool water temperature.

The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the direct action of the steam pressure in the main steam lines will act against a spring loaded disk that will pop open when the valve inlet pressure exceeds the spring force. In the relief mode (or power actuated mode of operation), a pneumatic operator and mechanical linkage assembly are used to open the valve by overcoming the spring force, even with the valve inlet pressure equal to 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure reaches the spring lift set pressures. In the relief mode, valves may be opened manually or automatically at the selected preset pressure. Six of the S/RVs providing the relief function also provide the low-low set relief function specified in LCO 3.6.1.6, "Low-Low Set (LLS) Valves." Eight of the S/RVs that provide the relief function are part of the Automatic Depressurization System specified in LCO 3.5.1, "ECCS – Operating." The instrumentation associated with the relief valve function and low-low set function is discussed in the Bases for LCO 3.3.6.4, "Relief and Low-Low Set (LLS) Instrumentation,"

(continued)

BASES

BACKGROUND (continued)	and instrumentation for the ADS function is discussed in LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation."
APPLICABLE SAFETY ANALYSES	The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 2). For the purpose of the analyses, the 13 safety valves with the highest setpoints were assumed to be operational. Therefore, by requiring six S/RVs to be OPERABLE in the relief mode and seven in the safety mode, the accident analyses assumptions are adequately met. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the design basis event. Reference 3 discusses additional events that are expected to actuate the S/RVs. From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. S/RVs satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The safety function of seven S/RVs is required to be OPERABLE in the safety mode, and an additional six S/RVs (other than the seven S/RVs that satisfy the safety function) must be OPERABLE in the relief mode. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of seven S/RVs in the safety mode and six S/RVs in the relief mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded. The S/RV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or

(continued)

BASES

LCO (continued)	below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 are based on these setpoints, but also include the additional uncertainties of ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism. Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.
APPLICABILITY	In MODES 1, 2, and 3, the specified number of S/RVs must be OPERABLE since there may be considerable energy in the reactor core and the limiting design basis transients are assumed to occur. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the heat. In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.
ACTIONS	<u>A.1 and A.2</u> With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If one or more required S/RVs are inoperable, 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 12 hours and to MODE 4 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 3.4.4.1

This Surveillance demonstrates that the required S/RVs will open at the pressures assumed in the safety analysis of Reference 2. The demonstration of the S/RV safety function lift settings must be performed during shutdown, since this is a bench test, and in accordance with the INSERVICE TESTING PROGRAM. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

The Frequency was selected because this Surveillance must be performed during shutdown conditions and is based on the time between refuelings. The safety lift setpoints will still be set within a tolerance of ± 1%, but the setpoints will be tested to within ± 3% to determine acceptance or failure of the as-found valve lift setpoint (Reference 4).

SR 3.4.4.2

The required relief function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify the mechanical portions i.e., solenoids of the automatic relief function operate as designed when initiated either by an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function.

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

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.4.3

A manual actuation of each required S/RV (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 5), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed S/RVs based upon successful operation of a test sample of S/RVs.

Method 1:

Manual actuation of the S/RVs with verification by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the S/RVs divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow is achieved to perform this test. Adequate pressure at which this test is performed is consistent with the pressure recommended by the valve manufacturer.

Method 2:

The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during “as found” testing to verify proper operation of the S/RV.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.4.3 (continued)

The successful performance of the test sample of S/RVs provides reasonable assurance that the remaining installed S/RVs will perform in a similar fashion. After the S/RVs are replaced, the power-operated actuator of the newly installed S/RVs will be uncoupled from the S/RV stem and cycled to ensure proper operation of the control circuit and actuator. Following cycling, the power-operated actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function. If the valve actuator fails to operate due only to the failure of the solenoid but is capable of opening the valve on overpressure, the safety function of the S/RV is considered OPERABLE.

When removing and replacing the S/RVs, Foreign Material Exclusion controls will be in place to minimize the potential for unwanted materials from entering into any S/RV opening or the piping discharge lines.

SR 3.4.4.2 and the LOGIC SYSTEM FUNCTIONAL TEST performed in SR 3.3.6.4.4 overlap this surveillance to provide complete testing of the assumed safety function.

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

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. USAR, Chapter 15, Appendix 15B.
3. USAR, Section 15.
4. NRC Safety Evaluation to NEDC-31753P, March 8, 1993.
5. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE.

This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3).

The safety significance of leaks from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the drywell is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur detrimental to the safety of the facility or the public.

A limited amount of leakage inside the drywell is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the drywell atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

This LCO deals with protection of the 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.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 4 and 5) shows leak rates of hundreds of gallons per minute will precede crack instability (Ref. 6).

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor drain sump capacity.

RCS operational LEAKAGE satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

Pressure boundary LEAKAGE is prohibited as the leak itself could cause further RCPB deterioration, resulting in higher LEAKAGE.

(continued)

BASES

LCO (continued)

b. Unidentified LEAKAGE

Five gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell atmospheric monitoring, drywell floor drain sump level monitoring, and upper drywell air cooler condensate flow rate 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.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

(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

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the LEAKAGE. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE. However, the total LEAKAGE limit would remain unchanged.

C.1

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the leakage rate such that the current rate is less than the 2 gpm increase in the previous 24 hours; either by isolating the source or other possible methods) is to perform an evaluation to determine that the service sensitive Inconel 182 material in the nozzle welds of the reactor vessel, which is classified as “non-resistant material” to Intergranular Stress Corrosion Cracking (IGSCC), is not the source of the increased leakage.

The 4 hour Completion Time is needed to properly reduce the LEAKAGE increase or verify the source before the reactor must be shut down.

D.1 and D.2

If any Required Action and associated Completion Time is 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 MODE 3 within 12 hours and to MODE 4 within

(continued)

BASES

ACTIONS	D.1 and D.2 (continued) 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 3.4.5.1 The RCS LEAKAGE is monitored by a variety of instruments designed to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.7, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates. However, any method may be used to quantify LEAKAGE within the guidelines of Reference 7. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50.2. 2. 10 CFR 50.55a(c). 3. 10 CFR 50, Appendix A, GDC 55. 4. GEAP-5620, “Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws,” April 1968. 5. NUREG-75/067, “Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants,” October 1975. 6. USAR, Section 5.2.5.5.3. 7. Regulatory Guide 1.45, May 1973. 8. Deleted.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

RCS PIVs are defined as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB). The function of RCS PIVs is to separate the high pressure RCS from an attached low pressure system. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3). PIVs are designed to meet the requirements of Reference 4. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration.

The RCS PIV 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 these valves is not included in any allowable LEAKAGE specified in LCO 3.4.5, "RCS Operational LEAKAGE."

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 which could degrade the ability for low pressure injection.

A study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce intersystem LOCA probability.

PIVs are provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System;

b. Low Pressure Core Spray System;

(continued)

BASES

BACKGROUND (continued)	c. High Pressure Core Spray System; d. Reactor Core Isolation Cooling System; and e. Standby Liquid Control System. The PIVs are listed in Reference 6.
APPLICABLE SAFETY ANALYSES	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. PIV leakage is not considered in any Design Basis Accident analyses. This Specification provides for monitoring the condition of the RCPB to detect PIV degradation that has the potential to cause a LOCA outside of containment. RCS PIV leakage satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	RCS PIV leakage is leakage into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken. 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. The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. Reference 4 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). 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.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 3, valves in the RHR shutdown cooling flow path are not required to meet the requirements of this LCO when in, or during transition to or from, the RHR Shutdown Cooling mode of operation.

In MODES 4 and 5, 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. Accordingly, the potential for the consequences of reactor coolant leakage is far lower during these MODES.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 has been provided to modify the ACTIONS related to RCS PIV flow paths. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for the Condition of RCS PIV leakage limits exceeded provide appropriate compensatory measures for separate affected RCS PIV flow paths. As such, a Note has been provided that allows separate Condition entry for each affected RCS PIV 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. As a result, the applicable Conditions and Required Actions for systems made inoperable by PIVs must be entered. This ensures appropriate remedial actions are taken, if necessary, for the affected systems.

A.1

If leakage from one or more RCS PIVs is not within limit, the flow path must be isolated by at least one closed manual, deactivated automatic, or check valve within 4 hours.

(continued)

BASES

ACTIONS

A.1 (continued)

Required Action A.1 is modified by a Note stating that the check valves used for isolation must meet the same leakage requirements as the PIVs and must be on the RCPB or the high pressure portion of the system. A check valve may only be used for this purpose if leakage past the check valve did not exceed the allowable leakage limit at the last refueling outage, or after the last time the valve was known to have opened, whichever is more recent.

Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the flow path if leakage cannot be reduced while corrective actions to reseat the leaking PIVs are taken. The 4 hours allows time for these actions and restricts the time of operation with leaking valves.

B.1 and B.2

If leakage cannot be reduced or the system isolated, 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 12 hours and to MODE 4 within 36 hours. This action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The Completion Times are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

Performance of leakage testing on each RCS PIV is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition. For 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1 (continued)

The Frequency required by the INSERVICE TESTING PROGRAM is within the ASME Code Frequency requirement.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, GDC 55.
4. ASME Code for Operation and Maintenance of Nuclear Power Plants.
5. NUREG-0677, “The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes,” May 1980.
6. PNPP – Unit 1, Inservice Test Program.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (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.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms. The Bases for LCO 3.4.5, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of three independently monitored variables, such as sump level changes and drywell particulate and gaseous radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the drywell floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Nuclear Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump.

(continued)

BASES

BACKGROUND (continued)

The drywell floor drain sump level monitoring system contains sump level instrumentation. The drywell floor drain sump level monitoring system provides two separate indications of LEAKAGE to the control room. First the level instrumentation provides input into a differentiation circuit that indicates the rate of change of the drywell floor drain sump level. This leakage rate is displayed in the control room. An alarm is provided if the leakage rate exceeds a preset limit. In addition, sump level is indicated in the control room. This sump can also be used to determine leak rates by determining how much the sump level has changed over any specific period of time, and thus establishing the leak rate associated with the level change. Either of these two automatic methods of quantifying leak rates are acceptable for determining the unidentified LEAKAGE in accordance with the requirements of LCO 3.4.5, and thus if either of these two automatic methods are available, the drywell floor drain sump monitoring system can be considered OPERABLE. If the drywell floor drain sump monitoring system is inoperable, manual methods may be utilized. Such manual methods may be necessary when sump level switches are out-of-service such that operator actions are necessary to determine in leakage (manually starting or stopping the sump pump, or manually timing its operating time). To employ such manual methods, the pumping rate of the pump must have been determined within the last fuel cycle (i.e., approximately 24 months).

The drywell atmospheric monitoring systems continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room.

(continued)

BASES

BACKGROUND (continued)	Condensate from the two upper drywell air coolers is routed to the drywell floor drain sump and is monitored by a flow transmitter that provides indications and alarms in the control room. This upper drywell air cooler condensate flow rate monitoring system serves as an added qualitative indicator, but not quantifier, of RCS unidentified LEAKAGE.
APPLICABLE SAFETY ANALYSES	A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 3 and 4). Identification of the LEAKAGE allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 5). Therefore, these actions provide adequate response before a significant break in the RCPB can occur. RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
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 drywell floor drain sump monitoring system is required to quantify the unidentified LEAKAGE rate from the RCS. Thus, for the system to be considered OPERABLE, either the flow monitoring or the sump level monitoring portion of the system must be OPERABLE and capable of determining the leakage rate. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in unidentified LEAKAGE, depending on the origin and magnitude of the LEAKAGE. This sensitivity is acceptable for drywell sump monitor OPERABILITY.

(continued)

BASES

LCO (continued)

The reactor coolant contains radioactivity that, when released to the drywell, can be detected by the gaseous or particulate drywell atmospheric 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 and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate drywell atmospheric radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate drywell atmospheric radioactivity monitor is OPERABLE when it is capable of detecting activity equivalent to that assumed in the design calculations for the monitors (Reference 6).

An increase in humidity of the drywell atmosphere could indicate the release of water vapor to the drywell. Upper drywell air cooler condensate flow rate 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 upper drywell air cooler condensate flow rate monitor OPERABILITY.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system, in combination with a gaseous or particulate drywell atmospheric radioactivity monitor, and an upper drywell air cooler condensate flow rate monitoring system, provides an acceptable minimum.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1

With the drywell floor drain sump monitoring system inoperable, manual methods of determining the sump in leakage rate can provide the equivalent information to quantify leakage. In addition, the drywell atmospheric particulate or atmospheric gaseous monitor and the upper drywell air cooler condensate flow rate monitor will provide indications of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.5.1) using alternate methods such as the pump timer, operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still operable.

B.1

With both particulate and gaseous drywell atmospheric monitoring channels inoperable, grab samples of the drywell atmosphere shall be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 24 hours, the plant may continue operation since at least one other form of drywell leakage detection (i.e., upper drywell air cooler condensate flow rate monitoring system) is available. The 24 hour interval provides periodic information that is adequate to detect LEAKAGE.

(continued)

BASES

ACTIONS (continued)

C.1

With the required upper drywell air cooler condensate flow rate monitoring system inoperable, SR 3.4.7.1 is performed every 8 hours to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.4.7.1. The 8 hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leakage detection are available. However, this Required Action is modified by a Note that allows this action to be not applicable if the required drywell atmospheric monitoring system is inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.

D.1, D.2, D.3.1, and D.3.2

With the drywell floor drain sump monitoring system and the upper drywell air cooler condensate flow rate monitoring system inoperable, the only means of detecting LEAKAGE is the drywell atmospheric radiation monitor. A Note clarifies the applicability of the Condition. The drywell atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the drywell atmosphere must be taken and analyzed and monitoring of RCS leakage by administrative means must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of unidentified leakage. The administrative methods are monitoring drywell pressure and temperature, and manual timing of the drywell floor drain sump pumpout. These indications, coupled with the atmospheric grab samples, are sufficient to alert the operating staff to an unexpected increase in unidentified LEAKAGE.

(continued)

BASES

ACTIONS

D.1, D.2, D.3.1, and D.3.2 (continued)

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.

E.1 and E.2

With both the particulate and gaseous drywell atmospheric monitoring channels and the upper drywell air cooler condensate flow rate monitoring system inoperable, the only means of detecting LEAKAGE is the drywell floor drain sump monitoring system. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable monitoring systems 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 degraded configuration for a lengthy time period.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any Required Action of Condition A, B, C, D, or E cannot be 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 3 within 12 hours and to MODE 4 within 36 hours. 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.

G.1

With all required leakage detection systems inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric monitoring system. The check gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the relative accuracy of the instrumentation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.4.7.3 This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrumentation, including the instruments located inside the drywell. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 30. 2. Regulatory Guide 1.45, Revision 0, ''REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS,'' May 1973. 3. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flaws," April 1968. 4. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975. 5. USAR, Section 5.2.5.5.3. 6. USAR, Section 5.2.5.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Specific Activity

BASES

BACKGROUND

During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment.

Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure, in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 50.67 (Ref. 1).

This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 50.67 limit.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the USAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely.

This MSLB release forms the basis for determining offsite doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 50.67.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on specific activity are values from a parametric evaluation of typical site locations. These limits are conservative because the evaluation considered more restrictive parameters than for a specific site, such as the location of the site boundary and the meteorological conditions of the site.

RCS specific activity satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The specific iodine activity is limited to ≤ 0.2 μCi/gm DOSE EQUIVALENT I-131. These limits ensure the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 50.67 limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 4.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

A Note permits the use of the provisions of LCO 3.0.4.c. 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 a limiting event while exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1, B.2.1, B.2.2.1, and B.2.2.2

If the DOSE EQUIVALENT I-131 cannot be restored to $\leq 0.2\ \mu Ci/gm$ within 48 hours, or if at any time it is $> 4.0\ \mu Ci/gm$, it must be determined at least every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than a small fraction of the requirements of 10 CFR 50.67 during a postulated MSLB accident.

Alternately, the plant can be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for bringing the plant to MODES 3 and 4 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 3.4.8.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 50.67.

2. USAR, Section 15.6.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat removal is in preparation for performing maintenance operations, or for keeping the reactor in the Hot Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines or to the reactor via the LPCI injection path. The RHR heat exchangers transfer heat to the Emergency Service Water System (LCO 3.7.1, "Emergency Service Water (ESW) System-Divisions 1 and 2").

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR Shutdown Cooling System does not meet a specific criterion of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132), it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An RHR shutdown cooling subsystem is OPERABLE when the RHR pump, two heat exchangers in series, associated piping, valves, and instrumentation and controls are OPERABLE. Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote

(continued)

BASES

LCO (continued)

or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation (either continuous or intermittent) of one subsystem can maintain or reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS – Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

In MODE 3 with reactor steam dome pressure below the RHR cut in permissive pressure (i.e., the actual pressure at which the interlock resets) the RHR System may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

(continued)

BASES

APPLICABILITY (continued)

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System-Cold Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)-High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR) - Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1

With one required RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore, an alternate method of decay heat removal must be provided.

(continued)

BASES

ACTIONS

A.1 (continued)

The required cooling capacity of the alternate method should be sufficient to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as contributing to the alternate method capability. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System, or an inoperable but functional RHR shutdown cooling subsystem.

B.1

If the required alternate method of decay heat removal cannot be verified within one hour, immediate action must be taken to restore the inoperable RHR shutdown cooling subsystem to operable status. The Required Action will restore redundant decay heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

C.1

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be sufficient to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System, or an inoperable but functional RHR shutdown cooling subsystem.

D.1

If the required alternate methods of decay heat removal cannot be verified within one hour, immediate action must be taken to restore at least one RHR shutdown cooling subsystem to OPERABLE status. The immediate Completion Time reflects the importance of restoring a method of heat removal.

Required Action D.1 is modified by a Note indicating that all required MODE changes to MODE 4 may be suspended until one RHR shutdown

BASES

ACTIONS

Required Action D.1 is modified by a Note indicating that all required MODE changes to MODE 4 may be suspended until one RHR shutdown cooling subsystem is restored to OPERABLE status. In this case, LCO 3.0.3 and other Required Actions directing entry into MODE 4 could force the unit into a less safe condition in which there may be no adequate means to remove decay heat. It is more appropriate to allow the restoration of one of the RHR shutdown cooling subsystems before requiring entry into a condition in which that subsystem would be needed and exiting a condition where other sources of cooling are available. When at least one RHR subsystem is restored to OPERABLE status, the Completion Times of LCO 3.0.3 or other Required Actions resume at the point at which they were suspended.

E.1, E.2, and E.3

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or one recirculation pump must be restored without delay.

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the reactor coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note allowing sufficient time to align the RHR System for shutdown cooling operation after clearing the pressure interlock that isolates the system, or for placing a recirculation pump in operation.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant at ≤ 200°F. This decay heat removal is in preparation for performing refueling or maintenance operations, or for keeping the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of a motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines or to the reactor via the LPCI injection path.

APPLICABLE SAFETY ANALYSES

Decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR Shutdown Cooling System does not meet a specific criterion of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132), it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR Shutdown Cooling System is retained as a Technical Specification.

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and, when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem is OPERABLE when the RHR pump, two heat exchangers in series, associated piping, valves, and instrumentation and controls are OPERABLE. Additionally each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually

(continued)

BASES

LCO (continued)

aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be shut down for a period of 2 hours in an 8 hour period. Note 2 allows one RHR shutdown cooling subsystem to be inoperable for up to 2 hours for performance of surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy. Note 3 permits both RHR shutdown cooling subsystems and reactor recirculation pumps to be shutdown during performance of inservice leak testing and during reactor pressure vessel hydrostatic testing. This is permitted because RCS pressures and temperatures are being closely monitored during these tests as required by LCO 3.4.11, "RCS Pressure and Temperature (P/T) Limits."

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR cut in permissive pressure, this LCO is not applicable. Operation of the RHR System in the shutdown cooling mode is not allowed above this pressure because the RCS pressure may exceed the design pressure of the shutdown cooling piping. Decay heat removal at reactor pressures greater than or equal to the RHR cut in permissive pressure is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2 below this pressure, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS—Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

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BASES

APPLICABILITY (continued)

In MODE 4 when heat losses to the ambient are not sufficient to maintain average reactor coolant temperature ≤ 200°F, the RHR System may be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature ≤ 200°F. Ambient losses must be such that no increase in reactor vessel water temperature will occur even though MODE 4 conditions are being maintained. Otherwise, a recirculation pump is required to be in operation.

The requirements for decay heat removal in MODE 3 below the RHR cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown"; LCO 3.9.8, "Residual Heat Removal (RHR)—High Water Level"; and LCO 3.9.9, "Residual Heat Removal (RHR)—Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities.

(continued)

BASES

ACTIONS

A.1 (continued)

similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be sufficient to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as contributing to the alternate method capability. Alternate methods that can be used include (but are not limited to) the Fuel Pool Cooling and Cleanup System, the Reactor Water Cleanup System, the Alternate Decay Heat Removal System (ADHR), or an inoperable but functional RHR shutdown cooling subsystem.

B.1

If the required alternate method(s) of decay heat removal cannot be verified within one hour, immediate action must be taken to restore the inoperable RHR shutdown cooling subsystem(s) to OPERABLE status. The Required Action will restore redundant decay heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

C.1 and C.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as is permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem or recirculation pump), the reactor coolant temperature and pressure must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.10.1 This Surveillance verifies that one RHR shutdown cooling subsystem or recirculation pump is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	None.

B 3 4 REACTOR COOLANT SYSTEM (RCS)

B 3 4 11 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.

Figure 3.4.11-1 contains P/T limit curves for heatup, cooldown, and inservice leak and hydrostatic testing. The heatup curve provides limits for both heatup and criticality. Curves are provided which are valid for up to 32 EFPY.

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. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for 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 III, Appendix G (Ref. 2).

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 185-82 (Ref. 3) and 10 CFR 50, Appendix H

(continued)

BASES

BACKGROUND (continued)

(Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 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 criticality limits include the Reference 1 requirement that they be at least 40°F above the heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing.

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.

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, a condition that is unanalyzed. References 7 and 11 establish the methodology for determining the P/T limits. Since the P/T limits are not derived from any DBA, there are no acceptance

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

This LCO ensures that limits are met on RCS pressure, temperature, and heatup and cooldown rates. Elements of this LCO are:

a. RCS pressure, temperature, and heatup or cooldown rate are within limits during RCS heatup, cooldown, and inservice leak and hydrostatic testing.

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within limits during each recirculation pump startup, and also during increases in THERMAL POWER or loop flow while in single loop operation at low THERMAL POWER or loop flow.

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel meets the limit during each recirculation pump startup, and also during increases in THERMAL POWER or loop flow while in single loop operation at low THERMAL POWER or loop flow.

d. RCS pressure and temperature are within the criticality limits prior to control rod withdrawal for the purpose of achieving criticality.

e. The reactor vessel flange and the head flange temperatures are within limits when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leak and hydrostatic 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.

(continued)

BASES

LCO (continued)

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 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 evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired.

Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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 of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 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 brought to 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. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by bringing the plant to at least MODE 3 within 12 hours and to MODE 4 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

ACTIONS (continued)

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 200°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline.

SURVEILLANCE REQUIREMENTS

The limits imposed by this Specification are required to be met at all times, including periods when the vessel is defueled (except for limits that have an associated Note in a Surveillance Requirement specifically stating "Only required to be met…"). However, the Surveillance Requirements are not required to be performed at all times; rather, the SRs are required to be specifically performed during plant conditions or planned evolutions that are of primary concern for specific vessel components; see the Notes that state "Only required to be performed…" and "Not required to be performed until…"

SR 3.4.11.1

Verification that operation is within limits (i.e., to the right of the appropriate limit line, and within the applicable rate of temperature change limit) is required, even when defueled, when RCS pressure or temperature conditions are undergoing planned changes (when operator actions, inclusive of maintenance activities, can directly influence vessel pressures or temperatures). To reflect this requirement for when this SR verification must be performed, the SR has been modified by a Note that only requires this Surveillance to be performed during system heatup and cooldown operations and inservice leakage and hydrostatic testing. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1 (continued)

As noted on the Curve A figures, a maximum temperature change of less than or equal to 20°F in any one hour period has been established during inservice hydrostatic and leak testing operations above the pressure test curve (i.e., when operating to the right of curve A). If temperatures are changing faster than 20°F per hour before, during, or after a pressure test, Curve B must be applied.

Surveillance for heatup, cooldown, or inservice leakage and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.2

A separate limit curve is used when the reactor is approaching criticality and during subsequent plant heatup. Consequently, the RCS pressure and temperature must be verified within the appropriate limits (i.e., to the right of curve C) just before withdrawing the control rods that will make the reactor critical, and during the subsequent plant heatup. Performing SR 3.4.11.2 within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal. Performing SR 3.4.11.1 using the core critical limits every 30 minutes during the subsequent plant heatup is considered reasonable in view of the control room indication available to monitor RCS status.

This SR has been modified by a Note that requires this Surveillance to be met only during control rod withdrawal for the purpose of achieving criticality.

SR 3.4.11.3 and SR 3.4.11.4

Differential temperatures within the applicable limits ensure that metal thermal stresses and fuel thermal limits resulting from the startup of an idle recirculation pump will not exceed design allowances. In addition, compliance with these limits and ensuring that the operating loop flow rate is less than or equal to 50% of rated loop flow ensures that the assumptions of the analysis for the startup of an idle recirculation loop (Ref. 8 and 9) are satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the idle pump start. If, however, either the temperature differentials or loop flow rate exceed the limits, suspend startup of the idle pump.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.4 is to compare the temperatures of the operating recirculation loop and the idle loop.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.3 and SR 3.4.11.4 (continued)

SR 3.4.11.3 and SR 3.4.11.4 have been modified by a Note that requires the Surveillance to be met only in MODES 1, 2, 3, and 4 during recirculation pump start. In addition, SR 3.4.11.3 is only required to be met when reactor steam dome pressure ≥ 25 psig. In MODE 5, the overall stress on limiting components is lower; therefore, ΔT limits are not required.

SR 3.4.11.5, SR 3.4.11.6, and SR 3.4.11.7

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatups and cooldowns. However, in order to ensure the minimum temperature of 70°F is met before (and while) the flange is stressed by the full intended bolt preload (see USAR Section 5.3.2.1.1; Ref. 10), specific monitoring of flange temperature must be performed during operations

- approaching MODE 4 from MODE 5 (i.e., tensioning the head bolting studs when fuel is in the vessel),
- tensioning the head bolting studs when no fuel is in the vessel (no defined MODE), or
- in MODE 4 with RCS temperature less than or equal to certain specified values (100°F and 80°F).

Performance of these SRs provides additional assurance that the flange temperatures meet the LCO limits.

Regardless of the plant MODE, flange temperatures must be verified to be above the limits before and while tensioning the reactor vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 80°F, checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the flange temperature is required to ensure the temperatures are within limits.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.5, SR 3.4.11.6, and SR 3.4.11.7 (continued)

The applicable P/T limits are required to be met at all times, however the flange-specific SRs 3.4.11.6 and 3.4.11.7 are not required to be performed except in MODE 4 (head bolts fully tensioned) because:

1) as noted in the USAR (Ref. 10), the minimum temperature shown on the P/T figures is the fully preloaded boltup limit, and during the detensioning process, stresses on the flanges are being reduced, so the margin to brittle failure is increasing, and

2) when detensioning is complete, the bolting stresses on the studs and flange are relieved, so flange-specific SRs are not necessary until SR 3.4.11.5 becomes required again prior to and during tensioning of the head bolt studs.

During periods when these three flange SRs are not required to be performed, SR 3.4.11.1 remains in effect (regardless of fueled or defueled status), continuing to require monitoring of vessel temperatures when temperature conditions are undergoing planned changes (when operator actions, inclusive of maintenance activities, can directly influence vessel pressures or temperatures).

SR 3.4.11.8 and SR 3.4.11.9

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in THERMAL POWER or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.8 and SR 3.4.11.9 (continued)

recirculation loop flow provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.11.9 is to compare the temperatures of the operating recirculation loop and the idle loop.

Plant specific test data has determined that the bottom head is not subject to temperature stratification with natural circulation at power levels as low as 30% of RTP or with any single loop flow rate when the recirculation loop jet pump flow is > 50% of rated core flow. Thus, if THERMAL POWER is ≤ 30% RTP or if recirculation loop jet pump flow is ≤ 50% of rated core flow, THERMAL POWER and recirculation loop flow increases shall be suspended. Therefore, SR 3.4.11.8 and SR 3.4.11.9 have been modified by a Note that requires the Surveillance to be met only when THERMAL POWER or recirculation loop flow is being increased when the above conditions exist. The Note for SR 3.4.11.8 further states that the surveillance is only required to be met with reactor vessel steam dome pressure ≥ 25 psig. The Note for SR 3.4.11.9 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the idle loop cannot be introduced into the remainder of the Reactor Coolant System.

SR 3.4.11.10

Reactor coolant pressure boundary (RCPB) materials are subject to brittle failure below their nil-ductility temperature (NDT), at relatively low stresses. Below NDT, stresses are carefully limited by specifying both allowable pressure and heatup/cooldown rates. Steel ductility decreases steadily with exposure to neutron fluence.

The value of NDT used to set operating limits is called the nil-ductility reference temperature (RTNDT) which incorporates safety margin for variation in material properties and measurement. The actual shift in the RTNDT of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.10 (continued)

material specimens, in accordance with ASTM E 185-82 (Ref. 3) and 10 CFR 50, Appendix H (Ref. 4). The operating P/T limit curves in Figure 3.4 11-1 will be adjusted, as necessary, based on the evaluation findings and the recommendations of Reference 5

REFERENCES

1. 10 CFR 50, Appendix G
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests For Light-Water Cooled Nuclear Power Reactor Vessels," July 1982
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. GE-NE-0000-0000-8763-01, Revision 0, "Pressure-Temperature Curves For FirstEnergy Corporation, Using the K_{Ic} Methodology, Perry Unit 1," April 2002.
8. USAR, Section 15.4.4, "Abnormal Startup of Idle Recirculation Loop."
9. GE Services Information Letter, SIL No. 517 Supplement 1, "Analysis Basis for Idle Recirculation Loop Startup."
10 USAR, Sections 5.3.1.5, "Fracture Toughness," and 5.3.2, "Pressure-Temperature Limits."
11. Boiling Water Reactor Owners' Group Topical Report BWROG-TP-11-023-A, Revision 0, May 2013, "Linear Elastic Fracture Mechanics Evaluation of General Electric Boiling Water Reactor Water Level Instrument Nozzles for Pressure-Temperature Curve Evaluations."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of Design Basis Accidents (DBAs) and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1045 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analysis of DBAs and transients used to determine the limits for fuel cladding integrity MCPR (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The specified reactor steam dome pressure limit of ≤ 1045 psig ensures the plant is operated within the assumptions of the vessel overpressure protection analysis. Operation above the limit may result in a transient response more severe than analyzed.
APPLICABILITY	In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam, and events which may challenge the overpressure limits are possible.

(continued)

BASES

APPLICABILITY (continued)	In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.
ACTIONS	A.1 With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident while pressure is greater than the limit is minimal. B.1 If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.4.12.1 Verification that reactor steam dome pressure is ≤ 1045 psig ensures that the initial conditions of the vessel overpressure protection analysis are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 5.2.2.2.2. 2. USAR, Section 15.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.1 ECCS - Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network is composed of the High Pressure Core Spray (HPCS) System, the Low Pressure Core Spray (LPCS) System, and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System. The ECCS also consists of the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tank (CST), it is capable of providing a source of water for the HPCS System.

On receipt of an initiation signal, each associated ECCS pump automatically starts; simultaneously the system aligns, and the pump injects water, taken either from the CST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed by a timer, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCS pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the spray sparger above the core. If the break is small, HPCS will maintain coolant inventory, as well as vessel level, while the RCS is still pressurized. If HPCS fails to maintain water level above Level 1, it is backed up by automatic initiation of ADS in combination with LPCI and LPCS. In this event, the ADS would time out and open the selected safety/relief valves (S/RVs), depressurizing the RCS and allowing the LPCI and LPCS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly, allowing the LPCI and LPCS systems to inject coolant into the core. Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool may be circulated through two heat exchangers in series cooled by the Emergency Service Water (ESW) System. Depending on the location and size of the break, portions of the ECCS may be ineffective; however

(continued)

BASES

BACKGROUND (continued)

the overall design is effective in cooling the core regardless of the size or location of the piping break. Although no credit is taken in the safety analysis for the RCIC System, it performs a similar function as HPCS but has reduced makeup capability. Nevertheless, it will maintain inventory and cool the core, while the RCS is still pressurized, following a reactor pressure vessel (RPV) isolation.

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS subsystems.

The LPCS System (Ref. 1) consists of a motor driven pump, a spray sparger above the core, piping, and valves to transfer water from the suppression pool to the sparger. The LPCS System is designed to provide cooling to the reactor core when the reactor pressure is low. Upon receipt of an initiation signal, the LPCS pump is automatically started after AC power is available. When the RPV pressure drops sufficiently, LPCS flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the LPCS System without spraying water into the RPV.

LPCI is an independent operating mode of the RHR System. There are three LPCI subsystems. Each LPCI subsystem (Ref. 2) consists of a motor driven pump, piping, and valves to transfer water from the suppression pool to the core. Each LPCI subsystem has its own suction and discharge piping and separate vessel nozzle that connects with the core shroud through internal piping. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, each LPCI pump is automatically started (C pump immediately after AC power is available, and A and B pumps approximately 5 seconds after AC power is available). When the RPV pressure drops sufficiently, LPCI flow to the RPV begins. RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the core. A full flow test line is provided to route water from and to the suppression pool to allow testing of each LPCI pump without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)

The HPCS System (Ref. 3) consists of a single motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suction source to the sparger. Suction piping is provided from the CST and the suppression pool. Pump suction can be aligned to either the suppression pool or the CST. However, only the capability to take suction from the suppression pool is required for OPERABILITY. If the CST volume is low or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCS System. The HPCS System is designed to provide core cooling over a wide range of RPV pressures (0 psid to 1200 psid, vessel to suction source). Upon receipt of an initiation signal, the HPCS pump automatically starts after AC power is available and valves in the flow path begin to open. Since the HPCS System is designed to operate over the full range of expected RPV pressures, HPCS flow begins as soon as the necessary valves are open. Full flow test lines are provided to route water from and to the suppression pool or CST to allow testing of the HPCS System during normal operation without spraying water into the RPV.

The ECCS pumps are provided with minimum flow lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed or RPV pressure is greater than the LPCS or LPCI pump discharge pressures following system initiation. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the ECCS discharge line "keep fill" systems are designed to maintain all pump discharge lines filled with water.

The ADS (Ref. 4) consists of 8 of the 19 S/RVs. It is designed to provide depressurization of the primary system during a small break LOCA if HPCS fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (LPCS and LPCI), so that these subsystems can provide core cooling. Each ADS valve is supplied with pneumatic power from an air storage system, which consists of air accumulators located in the drywell.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5, 6, and 7. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 8), and the results of these analyses are described in Reference 9.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 10), will be met following a LOCA assuming the worst case single active component failure in the ECCS:

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 zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 11. For a LOCA, HPCS System failure is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

Each ECCS injection/spray subsystem and eight ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are the three LPCI subsystems, the LPCS System, and the HPCS System. The ECCS injection/spray subsystems are further subdivided into the following groups:

a) The low pressure ECCS injection/spray subsystems are the LPCS System and the three LPCI subsystems;

b) The ECCS injection subsystems are the three LPCI subsystems; and

c) The ECCS spray subsystems are the HPCS System and the LPCS System.

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in 10 CFR 50.46 (Ref. 10) could potentially be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 10).

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the reactor coolant pressure boundary. In MODES 2 and 3, the ADS function is not required when pressure is ≤ 150 psig because the low pressure ECCS subsystems (LPCS and LPCI) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control."

(continued)

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCS subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCS subsystem, and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a LOCA may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability by assuming that various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1 and B.2

If the HPCS System is inoperable, and the RCIC System is verified to be OPERABLE (when RCIC is required to be OPERABLE), the HPCS System must be restored to OPERABLE status within 14 days. In this Condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with the ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCS is inoperable and RCIC is required to be OPERABLE. This may be performed by an administrative check, by examining logs or other

(continued)

BASES

ACTIONS (continued)

information, to determine if RCIC is out of service for maintenance or other reasons. It is not necessary to perform the Surveillance needed to demonstrate the OPERABILITY of the RCIC System. However, if the OPERABILITY of the RCIC System cannot be verified and RCIC is required to be OPERABLE, Condition D must be entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on the results of a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

C.1

With two ECCS injection subsystems inoperable or one ECCS injection and one ECCS spray subsystem inoperable, at least one ECCS injection/spray subsystem must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced in this Condition because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since the ECCS availability is reduced relative to Condition A, a more restrictive Completion Time is imposed. The 72 hour Completion Time is based on a reliability study, as provided in Reference 12.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A, B, or C 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 12 hours and to MODE 4 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

The LCO requires eight ADS valves to be OPERABLE to provide the ADS function. Reference 11 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only seven ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced because a single failure in the OPERABLE ADS valves could result in a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 14 day Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If any one low pressure ECCS injection/spray subsystem is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCS and the remaining low pressure ECCS injection/spray subsystems. However, the overall ECCS reliability is reduced because a single active component failure concurrent with a design basis LOCA could result in the minimum required ECCS equipment not being available. Since both a portion of a high pressure (ADS) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS injection/spray subsystem or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study (Ref. 12) and has been found to be acceptable through operating experience.

G.1 and G.2

If two or more ADS valves are inoperable or if any Required Action and associated Completion Time of Condition E or F are not met, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 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.

H.1

When multiple ECCS subsystems are inoperable, as stated in Condition H, the plant is in a degraded condition not specifically justified for continued operation, and may be in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCS System, LPCS System, and LPCI subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.2

Verifying the correct alignment for each manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper system response time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially 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.

This SR is modified by a Note that allows LPCI subsystems to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the RHR cut in permissive pressure in MODE 3, if

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.2 (continued)

capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

SR 3.5.1.3

Verification that ADS accumulator supply pressure is ≥ 150 psig assures adequate air pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least two valve actuations can occur with the drywell at 70% of design pressure (Ref. 13). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of 150 psig is provided by the Safety Related Instrument Air System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.4

The performance requirements of the ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 8). This periodic Surveillance is performed (in accordance with the ASME OM Code, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 10).

The differential pressure for each listed system in the Surveillance Requirements (SRs) 3.5.1.4, is the difference between the containment wetwell pressure and the RPV pressure assumed in the LOCA analyses at the time of injection/spray. In addition to this listed differential pressure, the ECCS pumps also need to overcome

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

elevation head loss and piping system friction loss at the required flow rate. This safety analysis value is determined by engineering calculation. In addition, pump operability may be limited by the ASME “required action” range value for these pumps. The Frequency for this Surveillance is in accordance with the INSERVICE TESTING PROGRAM requirements.

SR 3.5.1.5

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCS, LPCS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves to their required positions. This Surveillance also ensures that the HPCS System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool on a condensate storage tank low water level signal and on a suppression pool high water level signal. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, “Emergency Core Cooling System (ECCS) Instrumentation,” overlaps this Surveillance to provide complete testing of the assumed safety function.

HPCS testing may be performed in any MODE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the full flow test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.6

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to verify that the mechanical portions (i.e., solenoids) of the ADS function operate as designed when initiated either by an actual or simulated initiation signal. SR 3.5.1.7 and the LOGIC SYSTEM FUNCTIONAL TEST performed in SR 3.3.5.1.6 overlap this Surveillance to provide complete testing of the assumed safety function.

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

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.5.1.7

A manual actuation of each required ADS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed ADS valves based upon operation of a test sample of S/RVs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

Method 1:

Manual actuation of the ADS valve with verification by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow is achieved to perform this test. Adequate pressure at which this test is performed is consistent with the pressure recommended by the valve manufacturer.

Method 2:

The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during “as found” testing to verify proper operation of the S/RV. The successful performance of the test sample S/RVs provides reasonable assurance that the remaining installed S/RVs will perform in a similar fashion. After the S/RVs are replaced, the power-operated actuator of the newly installed S/RVs will be uncoupled from the S/RV stem and cycled to ensure proper operation of the control circuit and actuator. Following cycling, the power-operated actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function. If the valve actuator fails to operate due only to the failure of the solenoid but is capable of opening the valve on overpressure, the safety mode of the S/RV is considered OPERABLE.

When removing and replacing the S/RVs, Foreign Material Exclusion controls will be in place to minimize the potential for unwanted materials from entering into any S/RV opening or the piping discharge lines.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.7 (continued)

SR 3.5.1.6 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1.6 overlap this Surveillance to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.1.8

This SR ensures that the ECCS RESPONSE TIMES are within limits for each of the ECCS injection and spray subsystems. This SR is modified by a note which identifies that the associated ECCS actuation instrumentation is not required to be response time tested. Response time testing of the remaining subsystem components is required. This is supported by Reference 15. Response time testing acceptance criteria are included in Reference 16.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.8 (continued)

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

REFERENCES

1. USAR, Section 6.3.2.2.3.
2. USAR, Section 6.3.2.2.4.
3. USAR, Section 6.3.2.2.1.
4. USAR, Section 6.3.2.2.2.
5. USAR, Section 15.6.6.
6. USAR, Section 15.6.4.
7. USAR, Section 15.6.5.
8. 10 CFR 50, Appendix K.
9. USAR, Section 6.3.3.
10. 10 CFR 50.46.
11. USAR, Section 6.3.3.3.
12. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.
13. USAR, Section 5.2.2.4.1.
14. ASME Code for Operation and Maintenance of Nuclear Power Plants.
15. NEDO-32291, "System Analyses for Elimination of Selected Response Time Testing Requirements," January 1994.
16. USAR, Section 6.3, Table 6.3-1.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.2 Reactor Pressure Vessel (RPV) Water Inventory Control

BASES

BACKGROUND

The RPV contains penetrations below the top of the active fuel (TAF) that have the potential to drain the reactor coolant inventory to below the TAF. If the water level should drop below the TAF, the ability to remove decay heat is reduced, which could lead to elevated cladding temperatures and clad perforation. Safety Limit 2.1.1.3 requires the RPV water level to be above the top of the active irradiated fuel at all times to prevent such elevated cladding temperatures.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 4 or 5, RPV water inventory control is not required to mitigate any events or accidents evaluated in the safety analyses. RPV water inventory control is required in MODES 4 and 5 to protect Safety Limit 2.1.1.3 and the fuel cladding barrier to prevent the release of radioactive material to the environment should an unexpected draining event occur.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in MODES 4 and 5 due to the reduced RCS pressure, reduced piping stresses, and ductile piping systems. Instead, an event is considered in which an initiating event allows draining of the RPV water inventory through a single penetration flow path with the highest flow rate, or the sum of the drain rates through multiple penetration flow paths susceptible to a common mode failure (an event that creates a drain path through multiple vessel penetrations located below top of active fuel, such as loss of normal power, or a single human error). It is assumed, based on engineering judgment, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level.

Operating experience has shown RPV water inventory to be significant to public health and safety (Ref. 1, 2, 3, 4, and 5). Therefore, RPV Water Inventory Control satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The RPV water level must be controlled in MODES 4 and 5 to ensure that if an unexpected draining event should occur, the reactor coolant water level remains above the top of the active irradiated fuel as required by Safety Limit 2.1.1.3.

(continued)

BASES

LCO (continued)

The Limiting Condition for Operation (LCO) requires the DRAIN TIME of RPV water inventory to the TAF to be ≥ 36 hours. A DRAIN TIME of 36 hours is considered reasonable to identify and initiate action to mitigate unexpected draining of reactor coolant. An event that could cause loss of RPV water inventory and result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

One ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started from the control room to provide defense-in-depth should an unexpected draining event occur. OPERABILITY of the ECCS injection/spray subsystem includes any necessary valves, instrumentation, or controls needed to manually align and start the subsystem from the control room. A ECCS injection/spray subsystem is defined as either one of the three Low Pressure Coolant Injection (LPCI) subsystems, one Low Pressure Core Spray (LPCS) System, or one High Pressure Core Spray (HPCS) System. The LPCI subsystems and the LPCS System consist of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. The HPCS System consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV.

The LCO is modified by a Note which allows a required LPCI subsystem (A or B) to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of the restrictions on DRAIN TIME, sufficient time will be available following an unexpected draining event to manually align and initiate LPCI subsystem operation to maintain RPV water inventory prior to the RPV water level reaching the TAF.

APPLICABILITY

RPV water inventory control is required in MODES 4 and 5. Requirements on water inventory control in other MODES are contained in LCOs in Section 3.3, “Instrumentation,” and other LCOs in Section 3.5, “ECCS, RPV Water Inventory Control, and RCIC System.” RPV water inventory control is required to protect Safety Limit 2.1.1.3 which is applicable whenever irradiated fuel is in the reactor vessel.

(continued)

BASES (continued)

ACTIONS

A.1 and B.1

If the required ECCS injection/spray subsystem is inoperable, it must be restored to OPERABLE status within 4 hours. In this Condition, the LCO controls on DRAIN TIME minimize the possibility that an unexpected draining event could necessitate the use of the ECCS injection/spray subsystem, however the defense-in-depth provided by the ECCS injection/spray subsystem is lost. The 4 hour Completion Time for restoring the required ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considers the LCO controls on DRAIN TIME and the low probability of an unexpected draining event that would result in loss of RPV water inventory.

If the inoperable ECCS injection/spray subsystem is not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to establish a method of water injection capable of operating without offsite electrical power. The method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The method of water injection may be manually initiated and may consist of one or more systems or subsystems, and must be able to access water inventory capable of maintaining the RPV water level above the TAF for ≥ 36 hours. If recirculation of injected water would occur, it may be credited in determining the necessary water volume.

C.1 and C.2

With the DRAIN TIME less than 36 hours but greater than or equal to 8 hours, compensatory measures should be taken to ensure the ability to implement mitigating actions should an unexpected draining event occur. Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

The primary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action C.1 requires verification of the capability to establish the primary containment boundary in less than the DRAIN TIME. The required verification confirms actions to establish the primary containment boundary are preplanned and necessary materials are available.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Verification that the primary containment boundary can be established must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment. Primary containment penetration flow paths form a part of the primary containment boundary. Required Action C.2 requires verification of the capability to isolate each primary containment penetration flow path in less than the DRAIN TIME. The required verification confirms actions to isolate the primary containment penetration flow paths are preplanned and necessary materials are available. Power operated valves are not required to receive automatic isolation signals if they can be closed manually within the required time. Verification that the primary containment penetration flow paths can be isolated must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

D.1, D.2, and D.3

With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur. Note that if the DRAIN TIME is less than 1 hour, Required Action E.1 is also applicable.

Required Action D.1 requires immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by LCO. The additional method of water injection includes the necessary instrumentation and controls, water sources, and pumps and valves needed to add water to the RPV or refueling cavity should an unexpected draining event occur. The Note to Required Action D.1 states that either the ECCS injection/spray subsystem or the additional method of water injection must be capable of operating without offsite electrical power. The additional method of water injection may be manually initiated and may consist of one or more systems or subsystems. The additional method of water injection must be able to access water inventory capable of being injected to maintain the RPV water level above the TAF for ≥ 36 hours. The additional method of water injection and the ECCS injection/spray subsystem may share all or part of the same water sources. If recirculation of injected water would occur, it may be credited in determining the required water volume.

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

Should a draining event lower the reactor coolant level to below the TAF, there is potential for damage to the reactor fuel cladding and release of radioactive material. Additional actions are taken to ensure that radioactive material will be contained, diluted, and processed prior to being released to the environment.

The primary containment provides a control volume in which fission products can be contained, diluted, and processed prior to release to the environment. Required Action D.2 requires that actions be immediately initiated to establish the primary containment boundary.

The primary containment penetrations form a part of the primary containment boundary. Required Action D.3 requires that actions be immediately initiated to verify that each primary containment penetration flow path is isolated or to verify that it can be manually isolated from the control room.

E.1

If the Required Actions and associated Completion Times of Condition C or D are not met or if the DRAIN TIME is less than 1 hour, actions must be initiated immediately to restore the DRAIN TIME to ≥ 36 hours. In this condition, there may be insufficient time to respond to an unexpected draining event to prevent the RPV water inventory from reaching the TAF. Note that Required Actions D.1, D.2, and D.3 are also applicable when DRAIN TIME is less than 1 hour.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

This Surveillance verifies that the DRAIN TIME of RPV water inventory to the TAF is ≥ 36 hours. The period of 36 hours is considered reasonable to identify and initiate action to mitigate draining of reactor coolant. Loss of RPV water inventory that would result in the RPV water level reaching the TAF in greater than 36 hours does not represent a significant challenge to Safety Limit 2.1.1.3 and can be managed as part of normal plant operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

The definition of DRAIN TIME states that realistic cross-sectional areas and drain rates are used in the calculation. A realistic drain rate may be determined using a single, step-wise, or integrated calculation considering the changing RPV water level during a draining event. For a Control Rod RPV penetration flow path with the Control Rod Drive Mechanism removed and not replaced with a blank flange, the realistic cross-sectional area is based on the control rod blade seated in the control rod guide tube. If the control rod blade will be raised from the penetration to adjust or verify seating of the blade, the exposed cross-sectional area of the RPV penetration flow path is used.

The definition of DRAIN TIME excludes from the calculation those penetration flow paths connected to an intact closed system, or isolated by manual or automatic valves that are closed and administratively controlled, blank flanges, or other devices that prevent flow of reactor coolant through the penetration flow paths. A blank flange or other bolted device must be connected with a sufficient number of bolts to prevent draining. Normal or expected leakage from closed systems or past isolation devices is permitted. Determination that a system is intact and closed or isolated must consider the status of branch lines.

The Residual Heat Removal (RHR) Shutdown Cooling System is only considered an intact closed system when misalignment issues (Reference 6) have been precluded by functional valve interlocks or by isolation devices, such that redirection of RPV water out of an RHR subsystem is precluded. Further, RHR Shutdown Cooling System is only considered an intact closed system if its controls have not been transferred to Remote Shutdown, which disables the interlocks and isolation signals.

The exclusion of a single penetration flow path, or multiple penetration flow paths susceptible to a common mode failure, from the determination of DRAIN TIME should consider the effects of temporary alterations in support of maintenance (rigging, scaffolding, temporary shielding, piping plugs, freeze seals, etc.). If reasonable controls are implemented to prevent such temporary alterations from causing a draining event from a closed system, or between the RPV and the isolation device, the effect of the temporary alterations on DRAIN TIME need not be considered. Reasonable controls include, but are not limited to, controls consistent with the guidance in NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 4,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 (continued)

NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management,” or commitments to NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.”

Surveillance Requirement 3.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME requires that a new DRAIN TIME be determined.

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

SR 3.5.2.2 and SR 3.5.2.3

The minimum water level of 16 ft 6 in required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pump, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, the required ECCS injection/spray subsystem is inoperable unless aligned to an OPERABLE CST.

When the suppression pool level is < 16 ft 6 in, the HPCS System is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCS pump. Therefore, a verification that either the suppression pool water level is ≥ 16 ft 6 in or the HPCS System is aligned to take suction from the CST and the CST contains ≥ 249,700 gallons of water ensures that the HPCS System can supply makeup water to the RPV.

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

SR 3.5.2.4

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the required ECCS injection/spray subsystems full of water ensures that the ECCS subsystem will perform properly. This may also prevent a water hammer following an ECCS actuation. One acceptable method of ensuring that the lines are full is to vent at the high points.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.5

Verifying that the required ECCS injection/spray subsystem can be manually aligned, and the pump started and operated for at least 10 minutes demonstrates that the subsystem is available to mitigate a draining event. This SR is modified by two Notes. Note 1 states that testing the ECCS injection/spray subsystem may be done through the test return line to avoid overfilling the refueling cavity. Note 2 states that credit for meeting the SR may be taken for normal system operation that satisfies the SR, such as using the RHR mode of LPCI for ≥ 10 minutes. The minimum operating time of 10 minutes was based on engineering judgement.

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

SR 3.5.2.6

Verifying that each valve credited for automatically isolating a penetration flow path actuates to the isolation position on an actual or simulated RPV water level isolation signal is required to prevent RPV water inventory from dropping below the TAF should an unexpected draining event occur. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve 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 3.5.2.7

This Surveillance verifies that a required LPCI subsystem, LPCS System, or HPCS System can be manually aligned and started from the control room, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV.

The Surveillance is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. Information Notice 84-81, “Inadvertent Reduction in Primary Coolant Inventory in Boiling Water Reactors During Shutdown and Startup,” November 1984.

2. Information Notice 86-74, “Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves,” August 1986.

3. Generic Letter 92-04, “Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f),” August 1992.

4. NRC Bulletin 93-03, “Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs,” May 1993.

5. Information Notice 94-52, “Inadvertent Containment Spray and Reactor Vessel Draindown at Millstone 1,” July 1994.

6. General Electric Service Information Letter No. 388, “RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6,” February 1983.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), RPV WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of RPV water level. Under these conditions, the High Pressure Core Spray (HPCS) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 2) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the reactor vessel head spray nozzle. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, only the capability to take suction from the suppression pool is required for OPERABILITY. If the CST volume is low, or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from main steam line A, upstream of the inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, 165 psia to 1215 psia. Rated flow is required up to 1118 psia, based on operation of the Safety Relief Valves in the Relief and Low-Low-Set modes (T.S. 3.3.6.4) during the vessel isolation transients for which RCIC is designed. Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

(continued)

BASES

BACKGROUND (continued)	The RCIC pump is provided with a minimum flow line, which discharges to the suppression pool. The valve in this line automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the RCIC System discharge line "keep fill" system is designed to maintain the pump discharge line filled with water.
APPLICABLE SAFETY ANALYSES	The function of the RCIC System is to respond to transient events by providing makeup coolant to the reactor. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system is included in the Technical Specifications as required by the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity to maintain RPV inventory during an isolation event.
APPLICABILITY	The RCIC System is required to be OPERABLE in MODE 1, and MODES 2 and 3 with reactor steam dome pressure > 150 psig since RCIC is the primary non-ECCS water source for core cooling when the reactor is isolated and pressurized. In MODES 2 and 3 with reactor steam dome pressure ≤ 150 psig, the ECCS injection/spray subsystems can provide sufficient flow to the vessel. In MODES 4 and 5, RCIC is not required to be OPERABLE since RPV water inventory control is required by LCO 3.5.2, “RPV Water Inventory Control.”
ACTIONS	A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable RCIC system, and the

(continued)

BASES

ACTIONS (continued)

provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODES 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCS System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this Condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

RPV pressure since the HPCS System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of the HPCS system is therefore verified within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if the HPCS system is out of service for maintenance or other reasons. Verification does not require performing the Surveillance needed to demonstrate the OPERABILITY of the HPCS System. If the OPERABILITY of the HPCS System cannot be verified, however, Condition B must be entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCS) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC system to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming that various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of the similar functions of the HPCS and RCIC, the AOTs (i.e., Completion Times) determined for the HPCS system are also applied to the RCIC system.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCS System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge line of the RCIC System full of water ensures that the system will perform properly, injecting its full capacity into the Reactor Coolant System upon demand. This will also prevent a water hammer following an initiation signal. One acceptable method of ensuring the line is full is to vent at the high points. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.3.2

Verifying the correct alignment for manual, power operated, and automatic valves in the RCIC flow path provides assurance that the proper flow path will exist for RCIC 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 initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper system response time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. For the RCIC System, this SR also includes the steam flow path for the turbine and the flow controller position.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.3 and SR 3.5.3.4

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Since the required reactor steam pressure must be available to perform SR 3.5.3.3 and SR 3.5.3.4, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillance are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test.

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

SR 3.5.3.5

The RCIC System is required to actuate automatically to perform its design function. This Surveillance verifies that with a required system initiation signal (actual or simulated) the automatic initiation logic of RCIC will cause the system to operate as designed, including actuation of the system throughout its emergency operating sequence,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.5 (continued)

automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance test also ensures that the RCIC System will automatically restart on an RPV low water level (Level 2) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool on a condensate storage tank low water level signal and on a suppression pool high water level signal. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.3, “Reactor Core Isolation Cooling (RCIC) System Instrumentation,” overlaps this Surveillance to provide complete testing of the assumed safety function.

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

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the full flow test line, coolant injection into the RPV is not required during the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 33.

2. USAR, Section 5.4.6.

3. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCO's for ECCS Components," December 1, 1975.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment—Operating

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Coolant System following a design basis Loss of Coolant Accident (LOCA) and to confine the postulated release of radioactive material to within limits. The primary containment consists of a free standing steel cylinder with an ellipsoidal dome, secured to a steel lined reinforced concrete mat, which surrounds the Reactor Coolant System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";

c. The equipment hatch is closed and sealed;

d. The leakage control systems associated with penetrations are OPERABLE, except as provided in LCO 3.6.1.8, "Feedwater Leakage Control System";

(continued)

BASES

BACKGROUND (continued)

e. The containment leakage rates are in compliance with the requirements of Specification 3.6.1.1 and Specification 3.6.1.3;

f. The suppression pool is OPERABLE; and

g. The sealing mechanism associated with each primary containment penetration, e.g., welds, bellows, or O-rings, is functional.

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a mechanistic fission product release following a DBA, based on NUREG 1465, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

Primary containment satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

Primary containment OPERABILITY is maintained by limiting leakage to < 1.0 L_a, except prior to the first unit startup after performing a required leakage test in accordance with the Primary Containment Leakage Rate Testing Program. At this time, the applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Individual leakage rates specified for the primary containment air locks are addressed in LCO 3.6.1.2.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment leakage limits are not required to be met in MODES 4 and 5 to prevent leakage of radioactive material from primary containment, (refer to LCO 3.6.1.10, "Primary Containment-Shutdown").

ACTIONS

A Note has been provided to indicate that when the Inclined Fuel Transfer System (IFTS) blind flange is unbolted for removal or re-installation, entry into associated Conditions and Required Actions may be delayed for up to 20 hours per 12 month period. This note only applies to the IFTS penetration and not to any other Primary Containment penetration. During removal and re-installation of the blind flange, a temporary condition will exist where the bolting will be loosened, hydraulic jacks will spread the flange faces, and normally about one half of the bolts will be removed while the blind is rotated. This condition is expected to exist for no more than 20 hours (10 hours to rotate out the blind and an additional 10 hours to re-install the blind). Upon expiration of the 20 hour allowance for this maintenance activity, if the IFTS blind flange has not yet been re-bolted, the applicable Condition must be entered and the Required Actions taken. With the bolts removed, the seismic restraint for the IFTS penetration is potentially challenged. The risk is to the bellows assembly, as exact displacements are not quantified. Failure of the ASME Class 2 bellows could result in a potential bypass of

(continued)

ACTIONS (continued)

Containment. This Note is based on a risk analysis (Ref. 9) of the time required to perform IFTS blind flange removal or installation. That analysis demonstrated that a 20 hour allowance per 12 month period does not significantly reduce the probability that the Primary Containment will be OPERABLE when necessary. Therefore, the total number of hours that the blind flange is unbolted per 12 month period shall be tracked to ensure the 20 hour assumption in the risk analysis is maintained. The 20 hour duration conservatively limits the seismic risk associated with the unbolted IFTS flange, yet provides adequate time to complete flange rotation.

A.1

In the event that primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods when primary containment is inoperable is minimal.

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 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 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage testing (SR 3.6.1.2.1 and SR 3.6.1.2.4), secondary containment bypass leakage (SR 3.6.1.3.9), resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.6), main steam isolation valve leakage (SR 3.6.1.3.10), or hydrostatically tested valve leakage (SR 3.6.1.3.11) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. The Frequency is required by the Primary Containment Leakage Rate Testing Program. An one-time exception to NEI 94-01, Section 9.2.3 has been approved by the NRC such that the first Type A test performed after the July, 1994 Type A test must be completed no later than June 29, 2009 (Reference 10).

The Appendix J, Option A exemptions approved to date are listed below. Appendix J, Option A exemptions that are applicable to Appendix J, Option B, may be utilized for Appendix J, Option B testing, unless they have been specifically revoked by the NRC (Ref. 3). Additionally, Bechtel Topical Report BN-TOP-1 may be utilized for ILRTs with a duration of less than 24 hours as noted in Reference 5 and in the Primary Containment Leakage Rate Testing Program.

a. Section III.D.2(b)(ii) - The air lock seal leakage test of Section III.D.2(b)(iii) of Appendix J may be substituted (following normal air lock door opening) for the full-pressure test provided that no maintenance has been performed that would affect the air locks sealing capability (Reference 6).

b. Section III.D.3 - A one time schedular Exemption was issued to permit Type C testing of certain containment isolation valves to exceed the two year interval, so that these tests could by conducted during the first refueling outage (Reference 7).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

c. Sections III.A.1(d), III.A.5(b)(2), III.B.3 and III.C.3 - The main steam lines between the inboard and outboard MSIVs (including the volume up to the outboard MSIV before seat drain line valves) are not required to be vented and drained for Type A testing and the main steam line isolation valve leak rates are exempted from inclusion in the overall integrated primary containment leak rate and the combined local leak rate (Reference 8).

d. Section III.D.1(a) - The third Type A test for each 10-year service period is not required to be conducted when the plant is shutdown for the 10-year plant inservice inspection (Reference 8).

e. Section III.D.3 - Type C local leak rate testing may be performed at other convenient intervals in addition to shutdown during refueling, but at intervals no greater than 2 years (Reference 8).

As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.6\ L_a$ for combined Type B and Type C leakage, and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $< 1.0\ L_a$. At $< 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis.

REFERENCES

1. USAR, Section 6.2.

2. USAR, Section 15.6.5.

3. 10 CFR 50, Appendix J, Option B.

4. Deleted.

5. Letter from NRC (B.J. Youngblood) to CEI (M.R. Edelman), "Performance of the Preoperational Containment Integrated Leak Rate Test - Perry Nuclear Power Plant, Unit 1," dated June 10, 1985.

(continued)

BASES

REFERENCES (continued)

6. PNPP Safety Evaluation Report Supplement 7, Section 6.2.6 "Containment Leakage Testing," November 1985.

7. Letter from NRC (T. Colburn) to CEI (A. Kaplan), "Exemption from 10 CFR Part 50, Appendix J", dated January 22, 1988.

8. Letter from NRC (J. Hopkins) to Centerior Services Company (D. Shelton), "Issuance of Exemption from the Requirements of 10 CFR Part 50, Appendix J - Perry Nuclear Power Plant, Unit 1", dated December 4, 1995.

9. Letter PY-CEI/NRR-2614L, "License Amendment Request Pursuant to 10 CFR 50.90: Inclined Fuel Transfer System (IFTS)," March 14, 2002.

10. Letter from NRC (S. Sands) to FENOC (W. Kanda), "Issuance of Amendment 126", dated April 8, 2003.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double door primary containment air locks have been built into the primary containment to provide personnel access to the primary containment and to provide primary containment isolation during the process of personnel entry and exit. The air locks are designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors has inflatable seals that are maintained ≥ 90 psig by the Service and Instrument Air System, which is maintained at a pressure ≥ 120 psig. Each door has two seals to ensure they are single failure proof in maintaining the leak tight boundary of primary containment.

Each air lock is nominally a right circular cylinder, with doors at each end that are interlocked to prevent simultaneous opening. The air locks are provided with limit switches on both doors in each air lock that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever both doors are simultaneously open. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions, as allowed by this LCO, the primary containment may be accessed through the air lock when the door interlock mechanism has failed, by manually performing the interlock function.

The primary containment air locks form part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a

(continued)

BASES

BACKGROUND (continued)

DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

APPLICABLE SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.20% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of 7.80 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the intermediate building.

Primary containment air locks satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the air locks. However, it was determined that a Specification should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the air locks during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

LCO

As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The primary containment air locks are required to be OPERABLE. For each 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

(continued)

BASES

LCO (continued)	allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single OPERABLE door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from primary containment.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining OPERABLE primary containment air locks in MODE 4 or 5 to ensure a control volume is only required during situations for which significant releases of radioactive material can be postulated; such as during movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, handling of fuel only requires primary containment air lock OPERABILITY when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. However, even though the air locks are not required to be OPERABLE during handling of fuel that is not recently irradiated, there are still controls provided to ensure the ability to close a door in an air lock should the need arise. Closure of a door, even though it is not OPERABLE, would reduce the potential for gross unfiltered leakage. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 4).
ACTIONS	The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component.

(continued)

BASES

ACTIONS (continued)

If the outer door is inoperable, then it may be easily accessed for most repairs. If the inner door is the one that is inoperable, then it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be

(continued)

BASES

ACTIONS (continued)

performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the primary containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary 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. Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by a third Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment—Operating," to be taken in this event.

<u>A.1, A.2, and A.3</u>

With one primary containment air lock door inoperable in one or more primary containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time (Required Action A.2). The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Required Action A.3 verifies that the affected air lock with an inoperable door has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary 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 controls. Allowing verification by administrative controls 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 air lock are inoperable. With both doors in the 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 Times 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.

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls required by Note 2 also permit entries and exits to respond to fire alarms and personnel safety concerns. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during the

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BASES

ACTIONS

A.1, A.2, and A.3 (continued)

entry and exit. The administrative controls also assure the OPERABLE door is relocked after completion of the containment entry and exit (the OPERABLE door need not be locked during the period when personnel are inside containment and the dedicated individual is stationed). This allowance is acceptable due to the low probability of an event that could pressurize the primary 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 both primary containment 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 one air lock are inoperable. With both doors in the 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 Times from the initial entry into Condition B; only the requirement to comply with the Required Actions. Note 2 allows entry into and exit from the primary 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). The administrative controls also ensure an OPERABLE door is relocked after completion of the containment entry and exit (a door need not be locked when personnel are inside containment and the dedicated individual is stationed). When an air lock concurrently has one inoperable door and an inoperable interlock mechanism, the function of this dedicated individual for Condition B (i.e., ensuring that only one door is opened at a time) does not override NOTE 1 to the ACTIONS. Specifically, opening of the OPERABLE door to perform repairs of the affected air lock components is permitted if necessary.

Required Action B.3 is modified by a Note that applies to

(continued)

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls 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 immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) 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 primary containment air locks must be verified closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in each affected air lock. The wording of Condition C, i.e., "... inoperable for reasons other than Condition A or B," should not be read as precluding separate Condition entry for each air lock. Specifically, an air lock may concurrently have both an inoperable door (Condition A) and an inoperable interlock mechanism (Condition B), with entry into Condition C not required.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time while operating in MODE 1, 2, or 3, 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 12 hours and to MODE 4 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

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time during movement of recently irradiated fuel assemblies in the primary containment, action is required to immediately suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program when in MODES 1, 2, and 3. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established prior to initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the combined Type B and C primary containment

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1 (continued)

leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The Appendix J exemption related to air lock testing approved to date for PNPP is:

> Section III.D.2(b)(ii) - The air lock seal leakage test of Section III.D.2(b)(iii) of Appendix J may be substituted (following normal air lock door opening) for the full-pressure test provided that no maintenance has been performed that would affect the air lock's sealing capability (Reference 5)

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 3.6.1.1.1 during operation in MODES 1, 2, and 3. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C primary containment leakage rate. Since the combined Type B and C primary containment leakage rate is only applicable in MODES 1, 2, and 3, the Note 2 requirement is imposed only during these MODES.

SR 3.6.1.2.2

The Service and Instrument Air System pressure in the header to the primary containment air lock is verified to be at ≥ 90 psig to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2.3

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure (Ref. 3), closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary 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 inner and outer door opening will not inadvertently occur. Due to the nature of this interlock, and given that the interlock mechanism is only challenged when the primary containment air lock door is opened, this test is only required to be performed upon entering or exiting a primary containment air lock. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.2.4

A seal pneumatic system test to ensure that pressure does not decay at a rate equivalent to > 1.5 psig for a period of 24 hours from an initial pressure of 90 psig is an effective leakage rate test to verify system performance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 3.8.
2. 10 CFR 50, Appendix J, Option B.
3. USAR, Table 6.2-1.
4. USAR, Section 15.7.6.
5. PNPP Safety Evaluation Report Supplement 7, Section 6.2.6 "Containment Leakage Testing," November 1985.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those PCIVs designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analysis will be maintained. Typically two barriers in series are provided for each penetration so that no credible single failure or malfunction of an active component can result in a loss of isolation or in leakage that exceeds limits assumed in the safety analysis. One of these barriers may be other than a PCIV, such as a closed system, while other penetrations may be designed with only one barrier such as a welded spare penetration. The isolation devices addressed by this LCO consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position, check valves with flow through the valve secured, and blind flanges are considered passive devices. Check valves and automatic valves designed to close without operator action following an accident, are considered active devices.

The 18 inch and outboard 42 inch primary containment purge supply and exhaust isolation valves are PCIVs that are qualified for use during all operational conditions. The 18 inch and outboard 42 inch primary containment purge supply and exhaust isolation valves are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness. The purge supply and exhaust isolation valves must be closed when not being used for pressure control, ALARA, air quality considerations for personnel entry, or surveillances or special testing on the purge system that require valves to be open to ensure that primary containment boundary assumed in the safety analysis will be maintained. Note that purge valve leakage is a contributor to the secondary containment bypass leakage totals.

(continued)

BASES

BACKGROUND (continued)	The Main Steam Isolation Valves (MSIVs) were originally designed to meet the required leakage criteria without any air source applied to the actuator of the valve. A design change for the four outboard valves has provided a safety-related air supply, which is applied at 45 psig during outboard valve leak tests. Therefore, the "B" train of the Safety Related Air System (P57) must be available during Modes 1, 2, and 3 to supply the required air source to maintain the outboard MSIVs leak tight within the required leakage limits following an accident.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by crediting PCIVs, are a loss of coolant accident (LOCA), and a main steam line break (MSLB) (Refs. 1 and 2). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through PCIVs are minimized. Of the events analyzed in Reference 1, the LOCA is the most limiting event due to radiological consequences. It is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The inboard 42 inch purge supply and exhaust valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3.

The outboard MSIVs must have a safety related air source available for use following an accident in order for leakage to be within limits. Therefore, anytime that this air source from the “B” train of P57 Safety Related Air System is not available, the outboard MSIVs may not be able to maintain valve leakage within the specified limits.

PCIVs satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the primary containment. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the primary containment during handling of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

(continued)

BASES (continued)

LCO

PCIVs form a part of the primary containment boundary and some also form a part of the RCPB. The PCIV safety function is related to minimizing the loss of reactor coolant inventory, and establishing primary containment boundary during a DBA.

The power operated isolation valves are required to have isolation times within limits. Additionally, power operated automatic valves are required to actuate on an automatic isolation signal. Primary containment purge supply and exhaust valves are not qualified to close under accident conditions and therefore must be sealed closed (inboard) or blocked to prevent full opening (outboard valves) to be OPERABLE.

The normally closed PCIVs or blind flanges are considered OPERABLE when, as applicable, manual valves are closed or opened in accordance with applicable administrative controls, automatic valves are de-activated and secured in their closed position, check valves with flow through the valve secured, or blind flanges are in place. The valves covered by this LCO with their associated stroke times, if applicable, are listed in Reference 3. Primary containment purge valves with resilient seals, secondary containment bypass valves, MSIVs, and hydrostatically tested valves must meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment-Operating," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory, and establish the primary containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be sealed closed in MODES 4 and 5. Certain valves are required to be OPERABLE, when the

(continued)

BASES

APPLICABILITY (continued)	associated instrumentation is required to be OPERABLE according to LCO 3.3.6.1, "Primary Containment and Drywell Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.) Due to radioactive decay, handling of fuel only requires containment isolation valve OPERABILITY when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 5).
ACTIONS	The ACTIONS are modified by a Note allowing penetration flow path(s) except for the inboard 42 inch (1M14-F045 and 1M14-F085) inch primary containment purge supply and exhaust isolation valve flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. Due to the size of the containment purge supply and exhaust

(continued)

BASES

ACTIONS (continued)

penetrations and the fact that those penetrations exhaust directly from the primary containment atmosphere to the environment, the penetration flow paths 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 the exception to SR 3.6.1.3.1 and Note 2 to SR 3.6.1.3.2.

A second Note has been added to provide clarification that, for the purpose of 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 PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. These Notes ensure appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve), or when the primary containment leakage limits are exceeded in MODES 1, 2, and 3. Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions to be taken.

The term "penetration" refers to piping/ductwork lines that pass through the primary containment boundary; these lines are isolable by PCIVs. This use of the term is separate and distinct from the Civil/Structural term "Penetration" used to describe the larger opening that multiple lines may pass through and which is sealed by welded steel plate or environmentally qualified material everywhere except where the lines pass through. When a PCIV becomes inoperable within a line, and the Required Action directs the operator to "isolate the affected penetration flowpath," the intent is to isolate only the line with the inoperable PCIV. It is not the intent to close off other lines that are unaffected by the inoperable PCIV.

<u>A.1 and A.2</u>
With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a PCIV check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest one available to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The specified time period of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be isolated should an event occur. This Required Action does not require any testing or isolation device manipulation. Rather, it involves verification that those isolation devices outside primary containment, drywell, and steam tunnel and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days for isolation devices outside primary containment, drywell, and steam tunnel," is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. For isolation devices inside primary containment, drywell, or steam tunnel, the specified time period of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days", is based on engineering judgment and is considered reasonable in view of

(continued)

ACTIONS

A.1 and A.2 (continued)

the inaccessibility of the isolation devices and the existence of other administrative controls ensuring that isolation device misalignment is an unlikely possibility.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified 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 low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except for inoperability due to leakage not within a limit specified in an SR for this Specification, either the inoperable PCIVs must be restored to OPERABLE status or 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 manual valve, a closed and de-activated automatic valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

C.1

With the secondary containment bypass leakage rate, hydrostatic leakage rate, or MSIV leakage rate not within limits, the assumptions of the safety analysis may not be met. Therefore, the leakage rate must be restored to within limit within 4 hours. Note that purge valve leakage is a subset to and should be included in secondary containment bypass leakage totals. The "except for purge valve leakage" statement in Condition C is applicable only if the purge valve penetration leakage exceeds its acceptance criteria of 0.05 L_a, but secondary containment bypass leakage limits continue to be met. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of a closed manual valve, a

(continued)

ACTIONS

C.1 (continued)

closed and de-activated automatic valve, or blind flange. When a penetration is isolated, the leakage rate for the isolation penetration is assumed to be the actual pathway leakage rate through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage rate of the two devices. The 4 hour Completion Time is reasonable considering the time required to restore the leakage rate by isolating the penetration and the relative importance to the overall containment function.

D.1, D.2, and D.3

In the event one or more primary containment purge valves 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 manual valve, a closed and de-activated automatic valve, and a blind flange. If a purge valve with resilient seals is utilized to satisfy Required Action D.1, it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.6. Note that purge valve leakage is a contributor to secondary containment bypass leakage, which, if also exceeded, has an additional Required Action per Action C. The specified Completion Time is reasonable, considering that one primary containment purge valve remains closed (refer to the requirement of SR 3.6.1.3.1; if this requirement is not met, entry into Conditions A and B, as appropriate, would also be required), so that a gross breach of primary containment does not exist.

For affected penetrations that have been isolated in accordance with Required Action D.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be isolated should an event occur. This Required Action does not require any testing or isolation device manipulation. Rather, it involves verification that those isolation devices outside primary containment and capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31

(continued)

ACTIONS

D.1, D.2, and D.3 (continued)

days for isolation devices outside primary containment," is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. For isolation devices inside primary containment the specified time period of "prior to entering MODE 2 or 3 from MODE 4, 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 the existence of other administrative controls ensuring that isolation device misalignment is an unlikely possibility.

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls 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 proper position, is low.

For each primary containment purge valve with resilient seals that is isolated in accordance with Required Action D.1, SR 3.6.1.3.6 must be performed at least once every 92 days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the primary containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.6 is 184 days. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown acceptable based on operating experience.

E.1 and E.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, 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

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BASES

ACTIONS

E.1 and E.2 (continued)

12 hours and to MODE 4 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.

F.1

If any Required Action and associated Completion Time cannot be met, action is required to suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended (Required Action F.1). Suspension of these activities shall not preclude completion of movement of a component to a safe condition.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

Each inboard 42 inch (1M14-F045 and 1M14-F085) primary containment purge supply and exhaust isolation valve is required to be verified sealed closed because the primary containment purge valves are not fully qualified to close under accident conditions. This SR is designed to ensure that a gross breach of primary containment is not caused by an inadvertent opening of a primary containment purge valve. Detailed analysis of these purge supply and exhaust isolation valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Primary containment purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power, removing the air supply to the valve operator, or providing administrative control of the valve control switches. In this application, the term "sealed" has no connotation of leak tightness. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows a valve that is open under administrative controls to not meet the SR during the time the valve is open. Opening a purge valve under administrative controls

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BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.1 (continued)

is restricted to one valve in a penetration flow path at a given time (refer to discussion for Note 1 of the ACTIONS) in order to effect repairs to that valve. This allows one purge valve to be opened without resulting in a failure of the Surveillance and resultant entry into the ACTIONS for this purge valve, provided the stated restrictions are met. Condition D must be entered during this allowance, and the valve opened only as necessary for effecting repairs. Each purge valve in the penetration flow path may be alternately opened, provided one remains sealed closed, if necessary, to complete repairs on the penetration.

The SR is modified by a Note stating that the inboard 42 inch primary containment purge supply and exhaust isolation valves are only required to be sealed closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves and the subsequent release of radioactive material will exceed limits prior to the closing of the purge valves. At other times when the purge valves are required to be capable of closing, pressurization concerns are not present and the purge valves are allowed to be open.

SR 3.6.1.3.2

This SR verifies that the 18 inch (1M14-F190, 1M14-F195, 1M14-F200, and 1M14-F205) and outboard 42 inch (1M14-F040 and 1M14-F090) primary containment purge supply and exhaust isolation 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 purge valve leakage outside the limits (Condition D).

The SR is also modified by a Note (Note 1) stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. At times other than MODE 1, 2, or 3 when the purge valves are required to be capable of closing, pressurization concerns are not present and the purge valves are allowed to be open (automatic isolation capability would be required by SR 3.6.1.3.5, SR 3.6.1.3.7, and SR 3.6.1.3.8).

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SURVEILLANCE REQUIREMENT

SR 3.6.1.3.2 (continued)

The SR is modified by a Note (Note 2) stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances or special testing on the purge system (e.g., testing of the containment and drywell ventilation radiation monitors) that require the valves to be open. These primary containment purge 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 3.6.1.3.3

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment, drywell, and steam tunnel and not locked, sealed, or otherwise secured, and is 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 primary containment boundary is within design limits. This SR does not require any testing or isolation device manipulation. Rather, it involves verification that those devices outside primary containment, drywell, and steam tunnel, and capable of being mispositioned, are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Three Notes are added to this SR. Note 1 provides an exception to meeting this SR in MODES other than MODES 1, 2, and 3. When not operating in MODES 1, 2, or 3, the primary containment boundary, including verification that required penetration flow paths are isolated, is addressed by LCO 3.6.1.10, "Primary Containment-Shutdown" (SR 3.6.1.10.1). The second Note applies to valves and blind flanges located in high radiation areas and allows them to be verified 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, and 3 for ALARA reasons. Therefore, the probability of misalignment of these isolation devices, once they have been

(continued)

BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.3 (continued)

verified to be in the proper position, is low. A third Note is included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time the PCIVs are open.

SR 3.6.1.3.4

This SR verifies that each primary containment isolation manual valve and blind flange located inside primary containment, drywell, or steam tunnel, 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 the primary containment boundary is within design limits. For devices inside primary containment, drywell, or steam tunnel, the Frequency of "prior to entering MODE 2 or 3 from MODE 4, if not performed within the previous 92 days," is appropriate since these devices are operated under administrative controls and the probability of their misalignment is low. 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.

Four Notes are added to this SR. Note 1 provides an exception to meeting this SR in MODES other than MODES 1, 2, and 3. When not operating in MODES 1, 2, or 3, the primary containment boundary, including verification that required penetration flow paths are isolated, is addressed by LCO 3.6.1.10, "Primary Containment- Shutdown" (SR 3.6.1.10.1). The second Note allows valves and blind flanges located in high radiation areas to be verified 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, and 3 for ALARA reasons. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in their proper position, is low. A third Note is included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open.

A fourth Note addresses removal of the Inclined Fuel Transfer System (IFTS) blind flange in MODES 1, 2, and 3 for up to 60 days per cycle. The 60 days per operating cycle is

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BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.4 (continued)

a risk-informed duration that provides the option of performing testing and maintenance of the IFTS during MODES 1, 2 or 3 prior to an outage. However, it is not meant for the movement of fuel. Removal of the IFTS blind flange during MODES 1, 2 or 3 requires the upper pool IFTS gate to be installed and requires the Fuel Handling Building Fuel Transfer Pool water level to be ≥ 40' above the bottom of the pool which ensures sufficient submergence of water over the bottom gate valve in the transfer tube to prevent direct communication between the Containment Building atmosphere and the Fuel Handling Building atmosphere, even upon occurrence of the peak post-accident pressure, P_a. Forty feet (40') above the bottom of the pool is equivalent to 22' 8 ¼" above the top of the flange for the IFTS bottom gate valve, which is approximately 3' 10" more water than needed to counteract the peak accident pressure of 7.8 psig. Also, since the IFTS drain piping does not have the same water seal as the transfer tube, administrative controls are required to ensure that the drain flow path can be quickly isolated whenever necessary.

These controls consist of designating an individual, whenever the 1F42-F003 valve is to be opened with the blind flange removed in MODE 1, 2, or 3, to be responsible for verifying closure of the valve if an accident occurs. This designated individual will remain in continuous communication with the control room, and be located at the 620' elevation in the Fuel Handling Area of the Intermediate Building. This person will be in addition to the minimum shift crew composition required to be at the plant site. Once the designated person is notified by the control room of the occurrence of an accident, his only assigned function will be to close this valve. The designated individual will verify the valve is closed from the controls at the IFTS panel if they are available. If this is not successful, the valve will be closed manually at the valve location. The designated person will be equipped with portable lighting (e.g., a flashlight) to supplement emergency lighting.

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BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.4 (continued)

The upper Containment pool gate (both inner and outer gates) between the IFTS pool and the dryer storage pool is required to be installed prior to IFTS blind flange removal during MODES 1, 2 or 3. With this gate installed, should a failure of an IFTS tube component occur the amount of water drained to the lower pools will be limited. Therefore, installing the upper pool IFTS gate provides single failure protection of upper pool water inventory for supporting the SPMU system. If the IFTS gate was not installed, the potential would exist to drain the upper pool volume, reducing the inventory available to the SPMU system to support make up to the suppression pool, which supports the ECCS design function during a LOCA. Reduced suppression pool volume and increased suppression pool temperature could result in a subsequent loss of suction pressure for the ECCS.

Also, to account for the upper containment pool water loss that would result from all leakage sources, including leakage through the upper Containment pool gate and leakage through the Fuel Pool Cooling and Clean-up (FPCC) siphon breaker supply lines; when the IFTS blind flange is removed in MODES 1,2 or 3, the upper containment pool level shall be maintained at ≥ 22 ft - 9 inches; and to account for possible leakage, the suppression pool is to be raised to ≥ 17 ft - 11.7 inches. These levels were determined via engineering calculation. Also, as a leakage prevention measure, the fuel transfer and storage pool supply isolation valve (G41-F0524) shall be closed to isolate the normal flow of FPCC supply water to the IFTS pool area.

Additional regulatory commitments to the NRC are required when the IFTS blind flange is removed in MODES 1, 2 or 3. These prerequisite administrative controls are controlled by plant procedures and are 1) the lower fuel transfer pool gates must be removed, and 2) Fuel Handling Building closure shall be in effect. Removal of the lower fuel transfer pool gates ensures control room monitoring exists for spent fuel pool level, which would assist in detecting a change in the fuel transfer pool water level in the event of an IFTS component failure. Establishing administrative controls for Fuel Handling Building closure when the IFTS blind flange is removed ensures that the Fuel Handling Area exhaust ventilation subsystem is in operation.

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BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.4 (continued)

Also, the drain piping motor-operated isolation valve is tested in accordance with the Primary Containment Leak Rate Test Program. The leakage rate on this valve will be controlled by the strict limits on potential secondary containment bypass leakage (SR 3.6.1.3.9). Thus, the combination of water seal in the Fuel Handling Building, pressure integrity of the IFTS transfer tube, and various administrative controls, creates acceptable barriers against post-accident leakage to the environment.

SR 3.6.1.3.5

Verifying the isolation time of each power operated and each automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV

(continued)

BASES

SURVEILLANCE REQUIREMENT

SR 3.6.1.3.5 (continued)

full closure isolation time is demonstrated by SR 3.6.1.3.7. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation time and Frequency of this SR are in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.1.3.6

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 4), is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Additionally, this SR must be performed within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened. A purge valve leak rate acceptance criterion of 0.05 L_a has been assigned to these valves. Note that purge valve leakage is a contributor to secondary containment bypass leakage, which has a separate acceptance criterion.

The SR is modified by a Note stating that the primary containment purge valves are only required to meet leakage rate testing requirements in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, purge valve leakage must be minimized to ensure offsite radiological release is within limits. At other times when the purge valves are required to be capable of closing, pressurization concerns are not present and the purge valves are not required to meet any specific leakage criteria.

SR 3.6.1.3.7

Verifying that the full closure isolation time of each MSIV is within the specified limits is required to demonstrate

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.7 (continued)

OPERABILITY. The full closure isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM. Additionally, the MSIVs must meet an average stroke time. This average stroke time shall be calculated using the stroke times of the fastest valve in each main steam line, and this average shall be ≥ 3 seconds.

SR 3.6.1.3.8

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA or other accidents. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.5 overlaps this SR to provide complete testing of the safety function. HPCS Injection Valve, 1E22-F004 and HPCS Test Valve to Supr Pool, 1E22-F023 may be tested in any MODE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.3.9

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 1 are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of a closed manual valve, a closed and de-activated automatic valve, or a blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.9 (continued)

device. If both isolation devices in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two devices.

A Note is added to this SR which states that these valves are only required to meet this leakage rate limit in MODES 1, 2, and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary leakage rate limits are not required. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

A second Note makes it clear that Main Steam Line leakage need not be added into the secondary containment bypass leakage total, since Main Steam Line leakage is addressed separately in the radiological dose calculations; is not assumed to be immediately released to the environment like bypass leakage is; and because it is separately measured in SR 3.6.1.3.10.

SR 3.6.1.3.10

The analyses in References 1 and 2 are based on leakage that is less than the specified leakage rate. Leakage through each main steam line must be ≤ 100 scfh when tested at ≥ P_a, and the total leakage rate through all four main steam lines is ≤ 250 scfh. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

If work is performed on a valve in a Main Steam Line following the satisfactory performance of as-found testing, the post maintenance testing must ensure that Main Steam Line leakage does not exceed 100 scfh and total leakage does not exceed 250 scfh, prior to entering MODES 1, 2, or 3.

The outboard MSIVs must have a safety related air source available for use following an accident in order for leakage to be within limits. Therefore, anytime that this air source from the “B” train of P57 Safety Related Air System is not available, the outboard MSIVs may not be able to meet this surveillance requirement.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.10 (continued)

A Note is added to this SR which states that these valves are only required to meet this leakage rate limit in MODES 1, 2, and 3. In other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage rate limits are not required.

SR 3.6.1.3.11

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 is met. The combined leakage rate must be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.11 (continued)

demonstrated at the frequency of the leakage test requirements of the Primary Containment Leakage Rate Testing Program.

This SR is modified by a Note that states these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage rate limits are not applicable in these other MODES or conditions.

A second Note states that the Feedwater lines are excluded from this particular hydrostatic (water) testing program. This is because water leakage from the stem, bonnet and seat of the third, high integrity valves in the feedwater lines (the gate valves) is controlled by the Primary Coolant Sources Outside Containment Program (Technical Specification 5.5.2). The acceptance criteria for the Primary Coolant Sources Outside Containment Program is 7.5 gallons per hour.

SR 3.6.1.3.12

Verifying that each outboard 42 inch (1M14-F040 and 1M14-F090) primary containment purge supply and exhaust isolation valve is blocked to restrict opening to ≤ 50° is required to ensure that the valves can close under DBA conditions within the time limits assumed in the analyses of References 2 and 3.

The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when the purge valves are required to be capable of closing, pressurization concerns are not present, thus the purge valves can be fully open. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.13

This SR ensures that the 2 inch Backup Hydrogen Purge System isolation valves are closed as required, or, if open, open for an allowable reason. These backup hydrogen purge isolation valves are fully qualified to close under accident conditions; therefore, these valves are allowed to be open for limited periods of time. This SR has been modified by a Note indicating the SR is not required to be met when the backup hydrogen purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or surveillances or special testing of the Backup Hydrogen Purge System (e.g., testing of the containment and drywell ventilation radiation monitors) that require the valves to be open. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Chapter 15.
2. USAR, Section 6.2.
3. Plant Data Book, Tab G.
4. 10 CFR 50, Appendix J, Option B.
5. USAR, Section 15.7.6

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Primary Containment Pressure

BASES

BACKGROUND

The primary containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

The limits on primary containment to secondary containment differential pressure have been developed based on operating experience. The shield building, which is the secondary containment, completely surrounds the primary containment. Therefore, the primary containment design external differential pressure, and consequently the Specification limit, are established relative to the shield building pressure. The shield building pressure is kept slightly negative relative to the atmospheric pressure to prevent leakage to the atmosphere.

Transient events, which include inadvertent containment spray initiation, can reduce the primary containment pressure (Ref. 1). Without an appropriate limit on the negative containment pressure, the design limit for negative internal pressure of 0.8 psid could be exceeded. Therefore, the Specification pressure limits of -0.1 and 1.0 psid were established (Ref. 2).

The limitation on the primary to secondary containment differential pressure provides added assurance that the peak LOCA primary containment pressure does not exceed the design value of 15 psig (Ref. 1).

APPLICABLE SAFETY ANALYSES

Primary containment performance for the DBA is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 3). Among the inputs to the design basis analysis is the initial primary containment internal pressure. The primary containment to secondary containment differential pressure can affect the initial containment internal pressure. The initial pressure limitation requirements ensure that peak primary containment pressure for a DBA LOCA does not exceed the design value of 15 psig and that peak negative pressure for an inadvertent

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	containment spray event does not exceed the design value of -0.8 psid. Primary containment pressure satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	A limitation on the primary to secondary containment differential pressure of ≥ -0.1 and ≤ 1.0 psid is required to ensure that primary containment initial conditions are consistent with the initial safety analyses assumptions so that containment pressures remain within design values during a LOCA and the design value of containment negative pressure is not exceeded during an inadvertent operation of containment sprays.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could result in a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining primary containment pressure within limits is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> When primary to secondary containment differential pressure is not within the limits of the LCO, differential pressure must be restored to within limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment-Operating," which requires that primary containment be restored to OPERABLE status within 1 hour. <u>B.1 and B.2</u> If primary to secondary containment differential pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in

(continued)

BASES

ACTIONS	B.1 and B.2 (continued) which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 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 3.6.1.4.1 Verifying that primary containment to secondary containment differential pressure is within limits ensures that operation remains within the limits assumed in the primary containment analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 6.2.1. 2. USAR, Section 6.2.1.1.4.2. 3. USAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Primary Containment Air Temperature

BASES

BACKGROUND	Heat loads from the drywell, as well as piping and equipment in the primary containment, add energy to the primary containment airspace and raise airspace temperature. Coolers included in the unit design remove this energy and maintain an appropriate average temperature inside primary containment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). This primary containment air temperature limit is an initial condition input for the Reference 1 safety analyses.
APPLICABLE SAFETY ANALYSES	Primary containment performance for the DBA is evaluated for a entire spectrum of break sizes for postulated loss of coolant accidents (LOCAs) inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial primary containment average air temperature. Analyses assume an initial average primary containment air temperature of 95°F. Maintaining the expected initial conditions ensures that safety analyses remain valid and ensures that the peak LOCA primary containment temperature does not exceed the maximum allowable temperature of 185°F (Ref. 1). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, and needed to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident. Primary containment air temperature satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	With an initial primary containment average air temperature less than or equal to the LCO temperature limit, the peak accident temperature is maintained below the primary containment design temperature. As a result, the ability of primary containment to perform its design function is ensured.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining primary containment average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

When primary containment average air temperature is not within the limit of the LCO, it must be restored within 8 hours. This Required Action is necessary to return operation to within the bounds of the primary 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 primary containment average air temperature cannot be restored to within 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 12 hours and to MODE 4 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 3.6.1.5.1

Verifying that the primary containment average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. In order to determine the primary containment average air temperature, an arithmetic average is calculated, using measurements taken at locations within the primary containment selected to provide a representative sample of the overall primary containment atmosphere.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1 (continued)

	Elevation	Azimuth
a.	720'-6"	280°
b.	720'-6"	100°
c.	689'-4"	40°
d.	689'-4"	210°
e.	647'-0"	54°
f.	645'-6"	251°
g.	613'-0"	69°
h.	613'-0"	251°

Use at least one reading from each elevation for an arithmetical average. However, all available instruments should be used in calculating the arithmetical average.

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

REFERENCES

1. USAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Low-Low Set (LLS) Valves

BASES

BACKGROUND	The safety/relief valves (S/RVs) can actuate either in the relief mode, the safety mode, the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (one of the power actuated modes of operation), a pneumatic operator and mechanical linkage assembly overcome the spring force and open the valve. The valve can be maintained open with valve inlet steam pressure as low as 0 psig. The pneumatic operator is arranged so that its malfunction will not prevent the valve disk from lifting if steam inlet pressure exceeds the safety mode pressure setpoints. Six of the S/RVs are equipped to provide the LLS function. The LLS logic causes two LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and causes all the LLS valves to stay open longer, such that reopening of more than one S/RV is prevented on subsequent actuations. Therefore, the LLS function prevents excessive short duration S/RV cycles with valve actuation at the relief setpoint. The instrumentation associated with the low-low set function is discussed in the Bases for LCO 3.3.6.4, "Relief and Low-Low Set (LLS) Instrumentation." Each S/RV discharges steam through a discharge line and quencher to a location below the minimum water level in the suppression pool, which causes a load on the suppression pool wall. Actuation at lower reactor pressure results in a lower load.
APPLICABLE SAFETY ANALYSES	The LLS mode functions to ensure that the containment design basis of one S/RV operating on "subsequent actuations" is met (Ref. 1). In other words, multiple simultaneous openings of S/RVs (following the initial opening) and the corresponding higher loads, are avoided. The safety analysis demonstrates that the LLS functions to avoid the induced thrust loads on the S/RV discharge line resulting from "subsequent actuations" of the S/RV during Design Basis Accidents (DBAs). Furthermore, the LLS function justifies the primary containment analysis assumption that multiple simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though six LLS S/RVs are

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	specified, all six LLS S/RVs do not operate in any DBA analysis. LLS valves satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	Six LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analysis (Ref. 2). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.
APPLICABILITY	In MODES 1, 2, and 3, an event could cause pressurization of the reactor and opening of S/RVs. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the LLS valves OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one LLS valve inoperable, the remaining OPERABLE LLS valves are adequate to perform the designed function. However, the overall reliability is reduced. The 14 day Completion Time takes into account the redundant capability afforded by the remaining LLS S/RVs and the low probability of an event in which the remaining LLS S/RV capability would be inadequate. <u>B.1 and B.2</u> If the inoperable LLS valve cannot be restored to OPERABLE status within the required Completion Time or if two or more LLS valves are inoperable, 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 12 hours and to MODE 4 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 3.6.1.6.1

A manual actuation of each required LLS valve (those valves removed and replaced to satisfy SR 3.4.4.1) is performed to verify that the valve is functioning properly. This SR can be demonstrated by one of two methods. If performed by Method 1, plant startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements (Ref. 4), prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for manual actuation after the required pressure is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If performed by Method 2, valve OPERABILITY has been demonstrated for all installed LLS valves based upon operation of a test sample of S/RVs.

Method 1:

Manual actuation of the LLS valve with verification by the response of the turbine control valves or bypass valves, by a change in the measured steam flow, or any other method suitable to verify steam flow (e.g., tailpipe temperature or acoustic monitoring). Adequate reactor steam pressure must be available to perform this test to avoid damaging the valve. Also, adequate flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the LLS valves divert steam flow upon opening. Sufficient time is therefore allowed after the required pressure and flow are achieved to perform this test. Adequate pressure at which this test is performed is consistent with the pressure recommended by the valve manufacturer.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Method 2:

The sample population of S/RVs tested to satisfy SR 3.4.4.1 will also be stroked in the relief mode during “as found” testing to verify proper operation of the S/RV. The successful performance of the S/RVs tested provides reasonable assurance that the remaining installed S/RVs will perform in a similar fashion. After the S/RVs are replaced, the power-operated actuator of newly-installed S/RVs will be uncoupled from the S/RV stem, and cycled to ensure proper operation of the control circuit and actuator. Following cycling, the power-operated actuator is recoupled and the proper positioning of the stem nut is independently verified. This verifies that each replaced S/RV will properly perform its intended function. If the valve actuator fails to operate due only to the failure of the solenoid but is capable of opening the valve on overpressure, the safety mode of the S/RV is considered OPERABLE.

When removing and replacing the S/RVs, Foreign Material Exclusion controls will be in place to minimize the potential for unwanted materials from entering into any S/RV opening or the piping discharge lines.

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

(continued)

BASES

SURVEILLANCE REQUIREMENT (continued)

SR 3.6.1.6.2

The LLS function S/RVs are required to actuate automatically upon receipt of specific initiation signals. A functional test is performed to verify that the mechanical portions (i.e., solenoids) of the automatic LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.4 overlaps this SR to provide complete testing of the safety function.

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

This SR is modified by a Note that excludes valve actuation. This prevents a reactor pressure vessel pressure blowdown.

REFERENCES

1. GESSAR-II, Appendix 3B, Attachment A, Section 3BA.8.
2. USAR, Section 7.6.1.11.
3. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage and low energy line breaks.

The RHR containment spray mode is operated post-LOCA, for up to 24 hours, in order to scrub released radionuclides from the containment atmosphere and into the suppression pool, and thus reduce the post-LOCA off-site and Control Room dose. Post-LOCA manual initiation for this function is based on a high radiation signal in the containment.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, two heat exchangers in series, and three spray spargers inside the primary containment (outside of the drywell). Dispersion of the spray water is accomplished by 346 nozzles in subsystem A and 344 nozzles in subsystem B.

The RHR containment spray mode will be automatically initiated for containment pressure reduction (based on pressure instrumentation), if required, following a LOCA. Containment spray is manually initiated for containment atmosphere post-LOCA dose mitigation, if required.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 1.68 ft^2. The analysis demonstrates that

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	with containment spray operation the primary containment pressure remains within design limits. The RHR Containment Spray System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	In the event of a Design Basis Accident (DBA), a minimum of one RHR containment spray subsystem is required to mitigate potential drywell bypass leakage paths and maintain the primary containment peak pressure below design limits, and provide for containment atmosphere dose reduction. To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the RHR pump, two heat exchangers in series, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR containment spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR containment spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE RHR containment spray subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time was chosen in light of the redundant RHR containment spray capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR containment spray subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1 and C.2

If the inoperable RHR containment spray subsystem 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 12 hours and to MODE 4 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 3.6.1.7.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow path provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation; rather, it involves verification 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1 (continued)

A Note has been added to this SR that allows RHR containment spray subsystems to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam pressure less than the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

SR 3.6.1.7.2

Verifying each RHR pump develops a flow rate ≥ 5250 gpm with flow through the associated heat exchangers ensures that pump performance has not degraded below the required flow rate during the cycle. It is tested in the suppression pool cooling mode to demonstrate pump OPERABILITY without spraying down equipment in primary containment. Flow is a normal test of centrifugal pump performance required by the ASME Code (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.1.7.3

This SR verifies that each RHR containment spray subsystem automatic valve actuates to its correct position upon receipt of an actual or simulated automatic actuation signal. Actual spray initiation is not required to meet this SR. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.2.5 overlaps this SR to provide complete testing of the safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.3 (continued)

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

SR 3.6.1.7.4

This Surveillance is performed following maintenance which could result in nozzle blockage using an inspection of the nozzle or an air or smoke flow test to verify that the spray nozzles are not obstructed and that flow will be provided when required. The frequency is adequate to detect degradation in performance due to the passive nozzle design and its normally dry state and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 6.2.1.1.5.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Feedwater Leakage Control System (FWLCS)

BASES

BACKGROUND

The FWLCS supplements the isolation function of the motor-operated primary containment isolation valves (PCIVs) in the feedwater lines that also penetrate the secondary containment. The motor-operated valve bonnets and internal seating volumes are sealed by water from the FWLCS to prevent fission products leaking past the isolation valves and bypassing the secondary containment after a Design Basis Accident (DBA) loss of coolant accident (LOCA).

The FWLCS consists of two independent, manually initiated subsystems, either of which is capable of preventing fission product leakage from the containment post LOCA. Each subsystem uses an ECCS water leg pump and a header which provides sealing water to pressurize the feedwater motor-operated valve bonnets and internal seating volumes.

APPLICABLE SAFETY ANALYSES

The analyses described in Reference 1 provide the evaluation of offsite dose consequences during accident conditions. For the Feedwater piping, a water seal would be maintained by the feedwater system outside the containment during the initial hour after a LOCA. That is, if the feedwater system becomes inoperable during the rapid vessel depressurization following a LOCA, the water within the feedwater piping will begin to flash into the drywell. A water seal would remain for a sufficient length of time following the accident until the operator remotely isolates the motor-operated valve. Thus, a water seal would exist in the piping beyond the motor-operated valve. Initiation of the FWLCS then provides the water seal for the remainder of the 30 days of the accident. The offsite dose consequence calculations include consideration of any FWLCS water leakage past the seats of the gate valves.

The FWLCS satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Two FWLCS subsystems must be OPERABLE such that in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. A FWLCS subsystem is OPERABLE when all necessary components are available to supply each feedwater motor-operated valve with sufficient sealing

(continued)

BASES

LCO (continued)

water pressure to preclude containment leakage when the containment atmosphere is at the maximum peak containment pressure, P_a.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the FWLCS is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

With one FWLCS subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE FWLCS subsystem is adequate to perform the leakage control function. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA, the amount of time available after the event for operator action to prevent exceeding this limit, the low probability of failure of the OPERABLE FWLCS subsystem, and the availability of the PCIVs.

B.1

With two FWLCS subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is based on the low probability of the occurrence of a DBA LOCA, the availability of operator action, and the availability of the PCIVs.

C.1 and C.2

If the inoperable FWLCS subsystem 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 12 hours and to MODE 4 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	<u>SR 3.6.1.8.1</u> Proper operation of the ECCS water leg pump is required to verify the capability of the FWLCS to provide sufficient sealing water to each feedwater motor-operated containment isolation valve to initiate and maintain the fluid seal for long term leakage control. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.6.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.9 Main Steam Shutoff Valves

BASES

BACKGROUND

The post accident function of the Main Steam Shutoff Valves (MSSVs) is to be remote-manually closed in order to provide a reduction of post accident dose associated with the main steam line leakage path. With the Shutoff valves in a closed position, mitigation of the off-site and Control Room dose is achieved by taking credit for the deposition of particulate forms of released fission products (aerosols) on the inner walls of the four main steam lines. This removal process is based on a "plug flow" model for the Main Steam Isolation Valve (MSIV) leakage with relatively even, slow cooldown of the insulated main steam lines. The closed position of the MSSV supports the plug flow model by providing isolation of the space just upstream of the MSSV from external convection which could originate from the downstream nonsafety side of the MSSV. Therefore, the MSSVs are required to move to a closed position, but are not required or credited with any tightness against leakage.

The Main Steam Shutoff Valves (1N11-F0020 A, B, C, and D) are safety-class, remote manual motor-operated valves. The operator response to provide the manually initiated closure for the MSSVs is 20 minutes post-LOCA (Ref. 1). Failure of all four motor-operated MSSVs to close is taken as a single active failure based on a single operator error or on a loss of divisional power. This failure is not coincident with a single MSIV failure to close.

APPLICABLE SAFETY ANALYSES

The applicable safety analyses are the off-site and Control Room radiolgical dose calculations. The MSIVs in the main steam lines are required to close when a design basis accident (DBA) occurs. Failure to close an MSIV would

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

affect the retention of the fission product aerosols in that main steam line (and therefore the fission product release to the environment), unless a holdup volume could be established downstream of the closed MSIV in that line, i.e., using the Main Steam Shutoff Valve (MSSV). In determining the most limiting single failure case that would result in the highest (most conservative) calculated off-site doses, two cases were examined.

1. The single MSIV failure to close case results in less off-site and Control Room dose (than failure of all four MSSVs to close) because of credit for particulate deposition in the downstream volumes out to the closed MSSVs.

2. Failure of all four MSSVs to close is taken as a single active failure based on a single operator error or on a loss of divisional power, and results in the most limiting dose consequences. This failure is not coincident with a single MSIV failure to close. This limiting case assumes that main steam line leakage is attenuated in the main steam line from the reactor vessel out to the outboard MSIV. Although this most limiting analysis case assumed a failure to close the MSSVs, retention of OPERABILITY requirements on these valves is appropriate to ensure the single failure analysis associated with the LOCA off-site and Control Room dose reanalysis remains valid. The Main Steam Shutoff Valves meet Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

The four MSSVs are part of the mitigation strategy for off-site and Control Room dose consequences. Failure of all four MSSVs to close is taken as a single active failure based on a single operator error or on a loss of divisional power, and results in the most limiting dose consequences. Although this most limiting analysis case assumed a failure to close the MSSVs, retention of OPERABILITY requirements on these valves is appropriate to ensure the single failure analysis associated with the LOCA off-site and Control Room dose reanalysis remains valid.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment. Therefore, MSSV OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the MSSVs OPERABLE is not required in MODE 4 or 5 to ensure MSIV leakage is processed.

ACTIONS

The ACTIONS are modified by a Note allowing separate condition entry for each penetration flow path because an inoperable Main Steam Shutoff Valve (MSSV) in a main steam line does not affect the ability to provide a post-accident holdup volume in the affected line or in the other lines (between the MSIVs or between an MSIV and an MSSV). The Required Actions provide appropriate compensatory actions for each inoperable MSSV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable MSSVs are governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1</u>

Each Main Steam Line has two Main Steam Isolation Valves (MSIVs) and a downstream Main Steam Shutoff Valve (MSSV), i.e., 1N11-F0020 A, B, C, or D. With one or more MSSVs inoperable, the inoperable MSSV must be restored to OPERABLE status or the Main Steam Line must be isolated within 30 days. During this 30 day Completion Time, the remaining OPERABLE MSIVs in that Main Steam Line are adequate to

(continued)

BASES

ACTIONS (continued)

perform the required leakage holdup function should a LOCA occur. However, the overall reliability is reduced because a single failure of an MSIV in that line could result in a loss of the MSIV leakage holdup function, because post-accident, a single MSIV failure would prevent establishment of a "holdup volume". If an MSSV is "inoperable", the action of closing the MSSV in that main steam line is based on the characteristics of the revised design basis accident source term (i.e., predominantly aerosol). Closing the MSSV will provide for a post-LOCA single-failure-proof holdup volume within the main steam line, for deposition of the aerosol on the inner walls of the main steam line. The Required Action does not permit closure of an MSSV and an MSIV at the same time, or both MSIVs at the same time, since doing so during plant operation could result in differential cooldown of that particular Main Steam Line, with resultant damage to some small-bore drain piping that is interconnected to the other Main Steam Lines. If an MSSV is "inoperable", but closed, credit can be taken for it in meeting the ACTION. Leak tightness of the MSSVs is not necessary to ensure the assumptions of the dose calculation methodology are met for the main steam lines, since leakage flow characteristics used in the analyses are affected only by the turbulence caused by an open ended pipe (i.e., the Main Steam Shutoff Valves fail to close).

The 30 day Completion Time is based on the redundant capability afforded by the OPERABLE MSIVs on that line, and the low probability of a DBA LOCA occurring during this period. After 30 days, when the MSSV on that line has been closed, a post-LOCA holdup volume can be established without concern over a single failure, therefore plant operation may continue.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status or the Main Steam line(s) cannot be isolated within the required Completion Time of Condition A, 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 12 hours and to MODE 4 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 3.6.1.9.1

The only necessary surveillance requirement is one to ensure the Main Steam Shutoff Valves will stroke closed on a manual demand by the operators. Leak test requirements are not necessary to ensure the assumptions of the dose calculation methodology are met for the main steam lines, since leakage flow characteristics used in the analyses are affected only by the turbulence caused by an open ended pipe (i.e., the Main Steam Shutoff Valves fail to close). The Frequency of this SR is in accordance with the INSERVICE TESTING PROGRAM.

(continued)

BASES (continued)

REFERENCES	1.	USAR Section 15.6.5.5.1.1

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.10 Primary Containment—Shutdown

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Coolant System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material to within limits. The primary containment surrounds the Reactor Coolant System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment. Additionally, this structure provides shielding from the fission products that may be present in the primary containment atmosphere following accident conditions.

The isolation devices for the penetrations in the primary containment boundary are a part of the primary containment leak tight barrier. To maintain this leak tight barrier for accidents during shutdown conditions:

a. All primary containment penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE primary containment automatic isolation system, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. Primary containment air locks are OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks"; and

c. The equipment hatch is closed.

(continued)

BASES

BACKGROUND (continued)	This Specification ensures that the performance of the primary containment, in the event of a fuel handling accident involving handling of recently irradiated fuel, provides an acceptable leakage barrier to contain fission products, thereby minimizing offsite doses.
APPLICABLE SAFETY ANALYSES	The safety design basis for the primary containment is that it contain fission products to limit doses at the site boundary to within limits. The primary containment OPERABILITY in conjunction with the automatic closure of selected OPERABLE containment isolation valves (LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," and LCO 3.3.6.1, "Primary Containment and Drywell Isolation Instrumentation"), assures a leak tight fission product barrier. The fuel handling accident calculations do not credit the primary or secondary containment; all gaseous fission products released from the water pool over the damaged fuel bundles are assumed to be immediately discharged directly to the environment (Ref. 2). During MODES 4 and 5, there are no accident analyses that credit the primary containment. However, it was determined that Specifications should remain in place per Criterion 4 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) to address fuel handling accidents. Criterion 3 of the NRC Policy Statement would apply if dose calculations are revised to credit the primary containment during handling of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).
LCO	Primary containment OPERABILITY is maintained by providing a contained volume to limit fission product escape following a fuel handling accident involving handling of recently irradiated fuel, or an unanticipated water level excursion. Compliance with this LCO will ensure a primary containment configuration, including the equipment

(continued)

BASES

LCO (continued)

hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis. Since offsite dose analyses conservatively assume LOCA leakage pathways and rates, the isolation and closure times of automatic containment isolation valves supports an OPERABLE primary containment during shutdown conditions. Furthermore, normal operation of the inclined fuel transfer system (IFTS) without the IFTS blind flange installed is considered acceptable for meeting Primary Containment-Shutdown OPERABILITY.

Leakage rates specified for the primary containment and air locks, addressed in LCO 3.6.1.1 and LCO 3.6.1.2 are not directly applicable during the shutdown conditions addressed in this LCO.

APPLICABILITY

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining an OPERABLE primary containment in MODE 4 or 5 to ensure a control volume, is only required during situations for which significant releases of radioactive material can be postulated; such as during movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, handling of fuel only requires OPERABILITY of Primary Containment when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 2).

ACTIONS

A.1

In the event that primary containment is inoperable, action is required to immediately suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.10.1

This SR verifies that each primary containment penetration that could communicate gaseous fission products to the environment during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive gases outside of the primary containment boundary is within design limits. 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 manual valve, a closed and de-activated automatic valve, and a blind flange. This SR does not require any testing or isolation device manipulation. Rather, it involves verification that these isolation devices capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by three Notes. The first Note does not require this SR to be met for pathways capable of being isolated by OPERABLE primary containment automatic isolation valves. The second Note permits the Fire Protection System manual hose reel containment isolation valves (1P54-F726 and 1P54-F727) to be open during shutdown conditions to supply fire mains. The third Note is included to clarify that manual valves opened under administrative controls are not required to meet the SR during the time the manual valves are open.

REFERENCES

1. Deleted.
2. USAR, Section 15.7.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.11 Containment Vacuum Breakers

BASES

BACKGROUND

The function of the containment vacuum breakers is to relieve vacuum when the primary containment depressurizes below outside atmospheric pressure. The design of the Containment Vacuum Relief System consists of four 24 inch vacuum relief lines. Each vacuum relief line has a 24 inch nominal diameter, free swinging, simple check valve inside containment. This check valve serves as both the vacuum breaker device and the inner containment isolation valve for the vacuum relief line. Outside containment, each vacuum relief line has a 24 inch nominal diameter motor operated butterfly valve to serve as the outer containment isolation valve.

Two of the vacuum breakers provide the vacuum relief cross-sectional area required to prevent the negative pressure inside containment from exceeding the design value of 0.8 psi during the events assumed in the analyses. The maximum depressurization rate is a function of the Residual Heat Removal (RHR) System containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the containment vacuum breakers are presented in Reference 1 as part of the accident response of the containment systems.

The safety analyses assume the containment vacuum breakers to be closed initially and to open at 0.1 psid (Ref. 1). Design Basis Accident (DBA) analyses require the vacuum breakers to be closed initially and to remain closed and leak tight with positive primary containment pressure.

Two cases were considered in the safety analyses to determine the adequacy of the containment vacuum breakers:

a. A small break loss of coolant accident in the Reactor Water Cleanup System followed by actuation of both RHR containment spray subsystems;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. Inadvertent actuation of both primary RHR containment spray subsystems during normal operation;

The results of these two cases show that the containment vacuum breakers, with an opening setpoint of 0.1 psid, are capable of maintaining the differential pressure within design limits.

The containment vacuum breakers satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the containment. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the containment during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

LCO

Only 3 of the 4 vacuum breakers must be OPERABLE for opening. All containment vacuum breakers, however, are required to be closed (except during testing or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the containment negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

APPLICABILITY

In MODES 1, 2, and 3, the RHR Containment Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside the containment could occur due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3, to mitigate the effects of inadvertent actuation of the RHR Containment Spray System.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining containment vacuum breakers OPERABLE is not required in MODE 4 or 5.

(continued)

BASES

APPLICABILITY (continued)

When handling recently irradiated fuel in the primary containment the primary containment is required to be OPERABLE. Containment vacuum breakers are therefore required to be OPERABLE during these evolutions to protect the primary containment against an inadvertent initiation of the Containment Spray System. Due to radioactive decay, handling of fuel only requires OPERABILITY of Containment Vacuum Breakers when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 2).

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment—Operating," when the containment vacuum relief subsystem leakage results in exceeding overall containment leakage rate criteria in MODES 1, 2, and 3.

A.1 and A.2

With one or two containment vacuum breakers open (except when open during testing or when the vacuum breakers are performing their intended design function), or with one of the three required containment vacuum breakers otherwise inoperable, the containment vacuum breaker(s) or associated isolation valve(s) must be closed within 4 hours. This assures that excessive containment leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is considered a reasonable length of time needed to complete the Required Action. This Condition applies to all four of the containment vacuum breakers when assuring the containment vacuum breakers are closed. This is to assure that unacceptable leakage does not occur, even through a containment vacuum breaker line that is not required for the vacuum relief function.

The required inoperable breaker(s) must be restored to OPERABLE status within 72 hours. The two remaining OPERABLE containment vacuum breakers provide sufficient vacuum relief capability for any event, but do not provide for a limiting single failure event.

The 72 hours takes into account a reasonable time for repairs, and the low probability of an event requiring the vacuum breakers to function during this period. Completion of this action within the 72 hours assures that at least three of the containment vacuum breakers can provide containment vacuum relief capability and that all four of the containment vacuum breakers are closed.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

A Note has been added to provide clarification that separate Condition entry is allowed for each containment vacuum breaker.

B.1 and B.2

If the Required Action of Condition A cannot be met, or if there are three or more containment vacuum breakers not closed, or if there are two or three required vacuum breakers inoperable for other reasons, the plant must be brought to a MODE or condition in which the LCO does not apply. To achieve this status, if the plant is operating, ACTION B.1 requires that the plant be brought to at least MODE 3 within 12 hours and that the plant be brought to MODE 4 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. A Note has been added to stipulate that these Required Actions are only applicable if the plant is in MODE 1, 2, or 3.

If the Condition occurs during movement of recently irradiated fuel in the primary containment, then ACTION B.2 requires that action be taken to immediately suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel in the primary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. A Note has been added to the Required Actions to stipulate that these requirements are only applicable while moving recently irradiated fuel assemblies in the primary containment.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.11.1

Each vacuum breaker is verified to be closed to ensure that this potential large leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Two Notes have been added to this Surveillance Requirement. The first Note states that the Surveillance is not required to be met when the vacuum breakers are open during other surveillance tests. Both SR 3.6.1.11.2 and SR 3.6.1.11.3 require the vacuum breakers to cycle open and closed. Therefore, the Note is added to clarify that the vacuum breakers do not have to be closed during these Surveillances. Note 2 states that the Surveillance is not required to be met when the vacuum breakers are performing their intended function (i.e., relieving a differential pressure condition between the containment atmosphere and the atmosphere outside containment). Small differential pressure conditions can exist during normal plant operation which could cause one or more of the vacuum breakers to open. Since these occurrences are normal, and are within the containment breakers' intended function, the Note is added to provide this clarification.

SR 3.6.1.11.2

Each required vacuum breaker and its associated isolation valve must be cycled through at least one complete cycle of full travel. This provides assurance that the safety analysis assumptions are valid. Performance of this SR includes a CHANNEL FUNCTIONAL TEST of the isolation valve actuation instrumentation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.1.11.3

Verification of each required vacuum breaker opening pressure differential is necessary to ensure that the safety analysis assumption that the vacuum breaker will begin to open at a differential pressure ≤ 0.1 psid and to be fully

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.11.3 (continued)

open at a differential pressure of ≤ 0.2 psid (outside containment to containment) is valid. Verification that the vacuum breaker isolation valves will open assures that the vacuum breakers are available to perform their intended function. Two of the vacuum breaker isolation valves have an opening allowable value of ≥0.052 psid and ≤0.148 psid, while the other two vacuum breaker isolation valves have an opening allowable of ≥0.064 psid and ≤0.160 psid (containment to outside containment).

Performance of this SR includes a CHANNEL CALIBRATION of the isolation valve actuation instrumentation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 6.2.1.1.4.2.
2. USAR, Section 15.7.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.12 Containment Humidity Control

BASES

BACKGROUND

Primary containment temperature and humidity are initial condition inputs into the analysis that evaluates the initiation of RHR containment spray during normal plant operation. A curve was determined of initial primary containment average temperature and humidity which would maintain peak vacuum inside containment ≤ 0.72 psi (design is ≤ 0.80 psi) during the spray initiation event. This curve then determines the containment average temperature-to-humidity combinations that are acceptable whenever the conditions exist for the inadvertent containment spray initiation event (whenever the primary containment leak tight barrier has been established).

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for the inadvertent initiation of the RHR Containment Spray System. The initial containment average temperature and relative humidity have an effect on the results of this analyses. As long as the average temperature and relative humidity is maintained within the limits of Figure B 3.6.1.12-1, the design can adequately perform in the inadvertent containment spray event.

There is no need to monitor the containment average temperature-to-relative humidity when the primary containment is not OPERABLE (i.e., has large enough openings such that a vacuum would not be created during an RHR containment spray event).

The containment relative humidity satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the containment. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the containment during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

(continued)

BASES (continued)

LCO

In the event RHR containment spray initiates during normal plant conditions, and while the primary containment is required to be OPERABLE, the initial average temperature and relative humidity must be within defined limits in order to assure proper response of the primary containment. When the primary containment is not OPERABLE, and contains sufficient openings such that a vacuum would not be created during a containment spray initiation, the average temperature and relative humidity are not required to be maintained within the prescribed limits.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the RHR Containment Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside the containment could occur due to inadvertent actuation of this system. The containment average temperature relationship with relative humidity, therefore, is required to be within limits in MODES 1, 2, and 3, to mitigate the effects of inadvertent actuation of the RHR Containment Spray System.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES. Therefore, maintaining limits on containment relative humidity and temperature is not required in MODE 4 or 5.

When handling recently irradiated fuel in the primary containment, the primary containment is required to be OPERABLE. Therefore, the proper relationship between containment average temperature and relative humidity must exist during these evolutions. Due to radioactive decay, handling of fuel only requires control over Containment humidity when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 2).

ACTIONS

A.1

With the primary containment average temperature and relative humidity not within the established limits, actions must be taken to restore the primary containment relative humidity and temperature to within limits. Required Action A.1 stipulates that restoration must occur within 8 hours. The eight hour Completion Time is based on the time required to restore the relative humidity and temperature limits, and the low probability of an event occurring during this time period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the primary containment relative humidity and temperature cannot be restored to within limits within the required Completion Time of Condition A, actions must be taken to place the plant in a MODE or condition in which the LCO does not apply.

Required Action B.1 requires that the plant be brought to at least MODE 3 within 12 hours and Required Action B.2 requires that the plant be brought to MODE 4 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

If the primary containment relative humidity and temperature cannot be restored to within limits within the required completion time of Condition A during movement of recently irradiated fuel in the primary containment, action is required to place the plant in a MODE or condition in which the LCO does not apply.

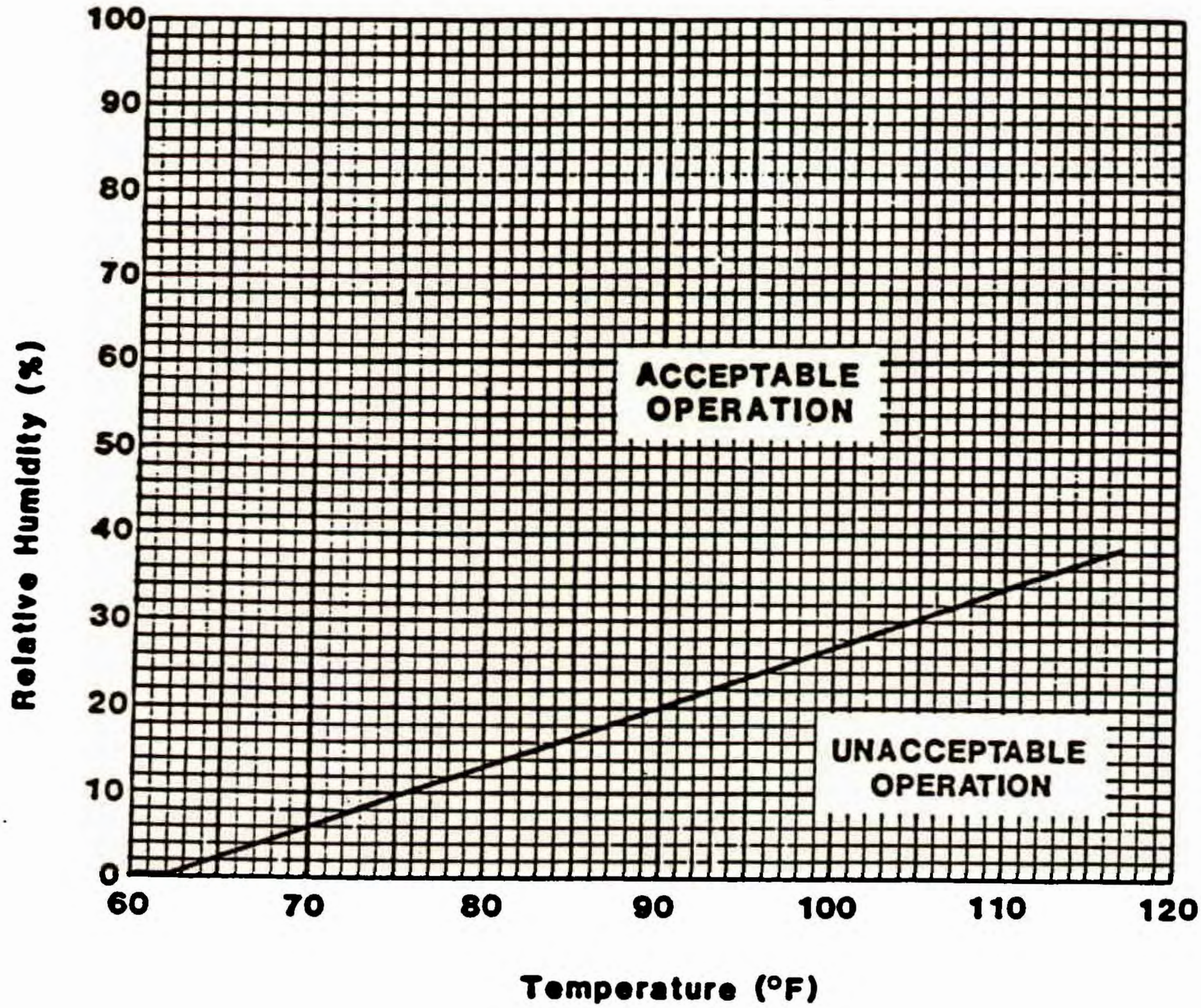
Required Action C.1 requires that actions be taken to immediately suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a condition that minimizes risk.

If applicable, movement of recently irradiated fuel in the primary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.12.1</u> Verifying that the primary containment average temperature and relative humidity are within limits ensures that operation remains within limits assumed in the primary containment analyses for initiation of RHR containment spray (Ref. 1). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 6.2.1.1.4.2. 2. USAR, Section 15.7.6.



CONTAINMENT AVERAGE TEMPERATURE vs RELATIVE HUMIDITY

Figure B 3.6.1.12-1

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression pool is a concentric open container of water with a stainless steel liner that is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling System turbine exhaust and provides the main emergency water supply source for the reactor vessel. The amount of energy that the pool can absorb as it condenses steam is dependent upon the initial average suppression pool temperature. The lower the initial pool temperature, the more heat it can absorb without heating up excessively. Since it is an open pool, its temperature will affect both primary containment pressure and average air temperature. Using conservative inputs and methods, the maximum calculated primary containment pressure during and following a Design Basis Accident (DBA) must remain below the primary containment design pressure of 15 psig. In addition, the maximum primary containment average air temperature must remain < 185°F.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation;

b. Primary containment peak pressure and temperature;

c. Condensation oscillation (CO) loads; and

d. Chugging loads.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (References 1 and 2). An initial pool temperature of 95°F is assumed for the Reference 1 and 2 analyses. Reactor

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

shutdown at a pool temperature of 110°F and vessel depressurization at a pool temperature of 120°F are assumed for the Reference 2 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during plant testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

A limitation on the suppression pool average temperature is required to assure that the primary containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are as follows:

a. Average temperature ≤ 95°F when THERMAL POWER is > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 105°F when THERMAL POWER is > 1% RTP and testing that adds heat to the suppression pool is being performed. This requirement ensures that the plant has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 95°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 95°F is short enough not to cause a significant increase in plant risk.

c. Average temperature ≤ 110°F when THERMAL POWER is ≤ 1% RTP. This requirement ensures that the plant will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

Note that when the reactor is producing power essentially equivalent to 1% RTP, heat input is approximately equal to normal system heat losses.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1 and 2 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above that assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool temperature to be restored to below the limit. Additionally, when pool temperature is > 95°F, increased monitoring of the pool temperature is required to ensure it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that suppression pool temperature increases relatively slowly except when testing that adds heat to the pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature 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, THERMAL POWER must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

C.1

Suppression pool average temperature is allowed to be > 95°F with THERMAL POWER > 1% RTP when testing that adds heat to the suppression pool is being performed. However, if temperature is > 105°F, the testing must be immediately suspended to preserve the pool's heat absorption capability. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1, D.2, and D.3

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Additionally, when pool temperature is > 110°F, increased monitoring of pool temperature is required to ensure that it remains ≤ 120°F. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high pool temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition. Additionally, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 4 within 36 hours.

E.1 and E.2

If suppression pool average temperature cannot be maintained ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours and the plant must be brought to MODE 4 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 without challenging plant systems.

Continued addition of heat to the suppression pool with pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. Average temperature is determined by taking an average of the functional suppression pool water temperature channels. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which testing will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequency is further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section 6.2.

2. USAR, Section 15.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression pool is a concentric open container of water with a stainless steel liner, which is located at the bottom of the primary containment. The suppression pool is designed to absorb the decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a loss of coolant accident (LOCA). The suppression pool must also condense steam from the Reactor Core Isolation Cooling (RCIC) System turbine exhaust and provides the main emergency water supply source for the reactor vessel.

The high water level limit and the low water level limit (indicated level of 18 ft 6 inches and 17 ft 9.5 inches respectively), are nominal values assuming a zero differential pressure across the drywell wall. These values include the water volume of the containment portion of the pool, the horizontal vents, and the weir annulus (including encroachments).

The suppression pool volume used in the short-term containment LOCA response analyses was 118,131 ft^3, which corresponds to an indicated water level of 18 ft 6 inches with the maximum negative drywell-to-containment differential pressure (-0.5 psid) and primary containment to secondary containment differential pressure (1.0 psid). This volume was used to maximize the negative effect of the suppression pool water volume on the drywell pressure and temperature response.

The suppression pool volume used in the long-term containment LOCA response analyses was 144,292 ft^3, which includes the 32,573 ft^3 makeup volume assumed from the upper containment pool, and corresponds to an indicated water level of 17 ft 9.5 inches with the maximum positive drywell-to-containment differential pressure (2.0 psid). This volume was used to maximize the containment pressure and temperature response results of the long term analyses. The limit on minimum suppression pool water level was set in order to satisfy the analyses for maximum drawdown of the suppression pool.

(continued)

BASES

BACKGROUND (continued)

When the reactor well to steam dryer storage pool gate is installed, the SPMU System available dump volume is reduced by 7472 ft^3. Consequently, the suppression pool level needs to be raised and maintained ≥ 18 ft 3.2 inches to compensate for the loss of volume in the upper containment pool. In addition, the upper containment pool level needs to be maintained ≥ 23 ft 0 inches above the reactor pressure vessel flange in combination with the increased suppression pool minimum water level when the reactor well to steam dryer storage pool storage pool gate is installed (Reference 2).

In order to account for positive drywell-to-containment differential pressures which affect indicated suppression pool water levels (but not volumes), a Suppression Pool Level Adjustment Table is contained in the Plant Data Book. This table lists water level adjustments for various drywell-to-containment differential pressures. The table adjustment factors are used to modify the indicted suppression pool water level to account for the positive drywell-to-containment differential pressures. Negative differential pressures are not required to be adjusted since these differential pressures were directly accounted for in the short-term analyses.

The suppression pool volumes (and corresponding adjusted levels) satisfy criteria or constraints imposed by: (1) maintaining a 2 foot minimum post-LOCA horizontal vent coverage to assure steam condensation/pressure suppression, and to maintain coverage over the RHR A Test Return line, (2) adequate ECCS pump NPSH, (3) adequate depth for vortex prevention, (4) adequate depth for minimum recirculation volume, and (5) minimizing hydrodynamic loads on submerged structures during SRV and horizontal vent steam discharges.

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid. Reference 3 contains an analysis for LOCAs in MODE 3 with reactor pressure equal to 235 psig.

Suppression pool water level satisfies Criteria 2 and 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES

LCO

The limits on suppression pool water level (≥ 17 ft 9.5 inches and ≤ 18 ft 6 inches) are required to assure that the primary containment conditions assumed for the safety analyses are met. Either high or low water level limits were used in the analyses, depending upon which is conservative for a particular calculation. The required suppression pool water level readings depend upon the drywell-to-containment differential pressure. The levels correspond to ≥ 17 ft 9.5 inches and ≤ 18 ft 6 inches for a 0 psid drywell-to-containment differential pressure. Adjusted levels are calculated for positive drywell-to-containment differential pressures to assure a proper suppression pool volume. When the reactor well to steam dryer storage pool gate is installed, the limits on the suppression pool water level are modified to ≥ 18 ft 3.2 inches and ≤ 18 ft 6 inches to assure that the primary containment conditions for the safety analyses are met (Reference 2).

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced because of the pressure and temperature limitations in these MODES. Requirements for suppression pool level in MODE 4 or 5 are addressed in LCO 3.5.2, “Reactor Pressure Vessel (RPV) Water Inventory Control”.

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analysis are not met. If water level is below the minimum level, the pressure suppression function still exists as long as horizontal vents are covered, RCIC turbine exhaust is covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and due to OPERABLE containment sprays. Prompt action to restore the suppression pool water level to within the normal range is prudent, however, to retain the margin to weir wall overflow from an inadvertent upper pool dump and reduce the risks of increased pool swell and dynamic loading. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within specified limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If suppression pool water level 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 12 hours and to MODE 4 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 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 6.2.
2. Numerical Applications Calculation, NAI-1863-002, Rev. 0, "Perry Nuclear Power Plant UCP Gate Installation Calculation" (Perry Calculation G43-009).
3. Numerical Applications Calculation NAI-1863-001, Rev. 0, "Perry Nuclear Power Plant Early Drain Down in MODE 3" (Perry Calculation 2.2.1.10).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling System

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems.

Each RHR subsystem contains a pump and two heat exchangers in series and is manually initiated and independently controlled. The two RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. Emergency service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink.

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to 185°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip without bypass or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool average water temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The analyses demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RHR Suppression Pool Cooling System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the RHR pump, two heat exchangers in series, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining RHR suppression pool cooling subsystem is adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced primary containment cooling capability. The 7 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

With two RHR suppression pool cooling subsystems inoperable, one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the primary containment pressure and temperature mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low probability of a DBA and the potential avoidance of a plant shutdown transient that could result in the need for the RHR suppression pool cooling subsystems to operate.

C.1 and C.2

If the Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 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 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to being locked, sealed, or secured. A valve that receives an initiation signal is allowed to be in the nonaccident position, provided the valve will automatically reposition in the proper stroke time. This is acceptable, since the RHR suppression pool cooling mode is manually initiated. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.3.2

Verifying each RHR pump develops a flow rate ≥ 7100 gpm with flow through the associated heat exchanger to the suppression pool, ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by the ASME Code (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is accordance with the INSERVICE TESTING PROGRAM.

REFERENCES

1. USAR, Section 6.2.

2. ASME Code for Operation and Maintenance of Nuclear Power Plants.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Suppression Pool Makeup (SPMU) System

BASES

BACKGROUND

The function of the SPMU System is to transfer water from the upper containment pool to the suppression pool after a loss of coolant accident (LOCA). For a LOCA, with Emergency Core Cooling System injection from the suppression pool, a large volume of water can be held up in the drywell behind the weir wall. This holdup can significantly lower suppression pool water level. The water transfer from the SPMU System ensures a post LOCA suppression pool vent coverage of ≥ 2 ft above the top of the horizontal vents so that long term steam condensation is maintained. The additional makeup water is used as part of the long term suppression pool heat sink. The post LOCA delayed transfer of this water to the suppression pool provides an initially low vent submergence, which results in lower drywell pressure loading and lower pool dynamic loading during a Design Basis Accident (DBA) LOCA as compared to higher vent submergence. The sizing of the residual heat removal heat exchanger takes credit for the additional SPMU System water mass in the calculation of the post LOCA peak containment pressure and suppression pool temperature.

The required water dump volume from the upper containment pool is equal to the difference between the total post LOCA drawdown volume and the assumed volume loss from the suppression pool. The total drawdown volume is the volume of suppression pool water that can be entrapped outside of the suppression pool following a LOCA. The post LOCA entrapment volumes causing suppression pool level drawdown include:

a. The free volume inside and below the top of the drywell weir wall;

b. The added volume required to fill the reactor pressure vessel from a condition of normal power operation to a post accident complete fill of the vessel, including the top dome;

c. The volume in the steam lines out to the inboard main steam isolation valve (MSIV) on three lines and out to the outboard MSIV on one line; and

(continued)

BACKGROUND (continued)

d. Allowances for primary containment spray holdup on equipment and structural surfaces.

Therefore as long as the total volume of the suppression pool and the upper containment pool meets the minimum required total water volume assumed in the analyses, the water volume of the upper containment pool can be varied.

The SPMU System consists of two redundant subsystems, each capable of dumping the makeup volume from the upper containment pool to the suppression pool by gravity flow. Each dump line includes two normally closed valves in series. The upper pool is dumped automatically on a suppression pool water level Low-Low signal (with a LOCA signal permissive) or on the basis of a timer following a LOCA signal alone to ensure that the makeup volume is available as part of the long term energy sink for small breaks that might not cause dump on a suppression pool water level Low-Low signal. A 30 minute timer was chosen, since the initial suppression pool mass is adequate for any sequence of vessel blowdown energy and decay heat up to at least 30 minutes.

Although the minimum freeboard distance above the suppression pool high water level limit of LCO 3.6.2.2, "Suppression Pool Water Level," to the top of the weir wall is adequate to preclude flooding of the drywell, a LOCA permissive signal is used to prevent an erroneous suppression pool level signal from causing a pool dump. In addition, the SPMU System mode switch may be keylocked in the "OFF" position to ensure that an inadvertent pool dump will not occur. Inadvertent actuation of the SPMU System during MODE 4 or 5 could create a radiation hazard to plant personnel due to a loss of shield water from the upper pool if irradiated fuel were in an elevated position.

APPLICABLE SAFETY ANALYSES

Analyses used to predict suppression pool temperature following large and small break LOCAs, which are the applicable DBAs for the SPMU System, are contained in References 1 and 2. During these events, the SPMU System is relied upon to dump upper containment pool water to maintain drywell horizontal vent coverage and an adequate suppression pool heat sink volume to ensure that the primary containment internal pressure and temperature stay within design limits. The analysis assumes an SPMU System dump volume of 32,573 ft^3 at a temperature of 110°F, with a total water

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

volume of 144,292 ft^3 in the upper containment pool and the suppression pool. Reference 4 contains an analysis for LOCAs in MODE 3 with reactor pressure equal to 235 psig.

The SPMU System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

During a DBA, a minimum of one SPMU subsystem is required to maintain peak suppression pool water temperature below the design limits (Ref. 1). To ensure that these requirements are met, two SPMU subsystems must be OPERABLE. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. The SPMU System is OPERABLE when the upper containment pool water temperature is ≤ 110°F, the piping is intact, and the system valves are OPERABLE. Additionally, the combined water levels of the upper containment pool and the suppression pool must be within limits. When the suppression pool level is maintained 2.2 inches greater than required by LCO 3.6.2.2, "Suppression Pool Water Level", the allowed upper containment pool water level limit is reduced to 22 ft 5 inches. Furthermore, when the reactor well to steam dryer storage pool gate is installed, the allowed upper containment pool water level limit must be maintained ≥ 23 ft 0 inches above the RPV flange, and the suppression pool water level must be increased and maintained at ≥ 18 ft 3.2 inches as per LCO 3.6.2.2 "Suppression Pool Water Level," (Reference 3).

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause heatup and pressurization of the primary containment. In MODES 4 or 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SPMU System OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

When the combined water level of the upper containment pool and suppression pool is not within limits, it is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. A sufficient quantity of water is necessary to ensure long term energy sink capabilities of the suppression pool and maintain water coverage over the uppermost horizontal vents. Loss of water volume has a relatively large impact on heat sink capability. Therefore, the combined water level of the upper containment pool and suppression pool must be restored to within limit within 4 hours.

(continued)

BASES

ACTIONS

A.1 (continued)

The 4 hour Completion Time is sufficient to provide makeup water to either the suppression pool or the upper containment pool to restore level within specified limit. Also, it takes into account the low probability of an event occurring that would require the SPMU System.

B.1

When upper containment pool water temperature is > 110°F, the heat absorption capacity is inadequate to ensure that the suppression pool heat sink capability matches the safety analysis assumptions. Increased temperature has a relatively smaller impact on heat sink capability. Therefore, the upper containment pool water temperature must be restored to within limit within 24 hours. The 24 hour Completion Time is sufficient to restore the upper containment pool to within the specified temperature limit. It also takes into account the low probability of an event occurring that would require the SPMU System.

C.1

With one SPMU subsystem inoperable for reasons other than Condition A or B, the inoperable subsystem must be restored to OPERABLE status within 7 days. The 7 day Completion Time is acceptable in light of the redundant SPMU System capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

D.1 and D.2

If any Required Action and associated Completion Time cannot be 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 12 hours and to MODE 4 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 3.6.2.4.1

The upper containment pool water level and, if applicable, the suppression pool water level, is regularly monitored to ensure that the required limits are satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Reference 3 contains the basis for the required water level in the upper containment pool when the reactor well to steam dryer storage pool gate is installed.

SR 3.6.2.4.2

The upper containment pool water temperature is regularly monitored to ensure that the required limit is satisfied. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.2.4.3

Verifying the correct alignment for manual, power operated, and automatic valves in the SPMU System flow path provides assurance that the proper flow paths will exist for system 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 positon 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 potentially 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.4.4

The upper containment pool has two gates used to separate the pool into distinct sections to facilitate fuel transfer and maintenance during refueling operations which, when installed, limit personnel exposure and ensure adequate water submergence of the separator when the separator is stored in the pool. The SPMU System dump line penetrations are located in the steam separator storage section of the pool. To provide the required SPMU System dump volume to the suppression pool, the steam dryer storage/reactor well pool gate must be removed (or placed in its stored position) to allow communication between the various pool sections. The Surveillance is modified by a NOTE that allows installation of the steam dryer storage pool to reactor well gate if upper pool level is maintained per SR 3.6.2.4.1.c. Additional restrictions are imposed on the IFTS system to prevent accidental draining of the fuel transfer pool that could detrimentally effect assumptions made within the design basis analyses by creating additional entrapment volume areas for containment sprays (Reference 5). The fuel transfer pool gate may be in place, removed, or placed in its stored position, during power operation when no 360 Platform Troughs are submerged in the upper containment pool, since the volume of water in the fuel transfer pool is not required for SPMU. However, the fuel transfer pool gate must be removed, or placed in its storage position when any 360 Platform Trough is installed in the upper containment pool during power operations, since the volume of water in the fuel transfer pool is required for SPMU due to the inventory loss from the installation of the troughs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.2.4.5

This SR verifies that each SPMU subsystem automatic valve actuates to its correct position on receipt of an actual or simulated automatic initiation signal. This includes verification of the correct automatic positioning of the valves and of the operation of each interlock and timer. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.4.6 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a NOTE that excludes makeup to the suppression pool. Since all active components are testable, makeup to the suppression pool is not required.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 6.2.

2. USAR, Chapter 15.

3. Numerical Applications Calculation, NAI-1863-002, Rev. 0, "Perry Nuclear Power Plant UCP Gate Installation Calculation" (Perry Calculation G43-009).

4. Numerical Applications Calculation NAI-1863-001, Rev. 0, "Perry Nuclear Power Plant Early Drain down in MODE 3" (Perry Calculation 2.2.1.10).

5. PRA Applications Analysis/Assessment Sequence No. PRA-PY1-15-003-R00, Rev. 0 "PRA Assessment of License Amendment Request for Drain Down of the Reactor Cavity Pool While in MODE 3". (Perry TAF 082015).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment and Drywell Hydrogen Igniters

BASES

BACKGROUND

The primary containment and drywell hydrogen igniters are a part of the combustible gas control required by 10 CFR 50.44 (Ref. 1) and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), to reduce the hydrogen concentration in the primary containment following a degraded core accident. The hydrogen igniters ensure the combustion of hydrogen in a manner such that containment overpressure failure is prevented as a result of a postulated degraded core accident.

10 CFR 50.44 (Ref. 1) requires boiling water reactor units with Mark III containments to install suitable hydrogen control systems. The hydrogen igniters are installed to accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water. This requirement was placed on reactor units with Mark III containments because they were not designed for inerting and because of their low design pressure. Calculations indicate that if hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water were to collect in primary containment, the resulting hydrogen concentration would be far above the lower flammability limit such that, without the hydrogen igniters, if the hydrogen were ignited from a random ignition source, the resulting hydrogen burn would seriously challenge the primary containment.

The hydrogen igniters are based on the concept of controlled ignition using thermal igniters designed to be capable of functioning in a post accident environment, seismically supported and capable of actuation from the control room. Hydrogen igniters are distributed throughout the drywell and primary containment in which hydrogen could be released or to which it could flow in significant quantities. The hydrogen igniters are arranged in two independent divisions such that each containment region has two igniters, one from each division, controlled and powered redundantly so that ignition would occur in each region even if one division failed to energize.

(continued)

BASES

BACKGROUND (continued)	When the hydrogen igniters are energized they heat up to a surface temperature ≥ 1700°F. At this temperature, they ignite the hydrogen gas that is present in the airspace in the vicinity of the igniter. The hydrogen igniters depend on the dispersed location of the igniters so that local pockets of hydrogen at increased concentrations would burn before reaching a hydrogen concentration significantly higher than the lower flammability limit.
APPLICABLE SAFETY ANALYSES	The hydrogen igniters cause hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 3). Burning occurs at the lower flammability concentration, where the resulting temperatures and pressures are relatively benign. Without the hydrogen igniters, hydrogen could build up to higher concentrations that could result in a violent reaction if ignited by a random ignition source after such a buildup. The hydrogen igniters are not included for mitigation of a Design Basis Accident (DBA) because an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water is far in excess of the hydrogen calculated for the limiting DBA loss of coolant accident (LOCA). The hydrogen concentration resulting from a DBA can be maintained less than the flammability limit using the primary containment hydrogen recombiners in conjunction with the Combustible Gas Mixing System. However, the hydrogen igniters have been shown by probabilistic risk analysis to be a significant contributor to limiting the severity of accident sequences that are commonly found to dominate risk for units with Mark III containment. The hydrogen igniters are considered to be risk significant in accordance with the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	Two divisions of primary containment and drywell hydrogen igniters must be OPERABLE, each with 90% or more of the igniters OPERABLE (i.e., no more than five igniters inoperable.)

(continued)

BASES

LCO (continued)

This ensures operation of at least one hydrogen igniter division, with adequate coverage of the primary containment and drywell, in the event of a worst case single active failure. This will ensure that the hydrogen concentration remains near 4.0 v/o.

APPLICABILITY

In MODES 1 and 2, the hydrogen igniter is required to control hydrogen concentration to near the flammability limit of 4.0 v/o following a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding. The control of hydrogen concentration prevents overpressurization of the primary containment. The event that could generate hydrogen in quantities sufficiently high enough to exceed the flammability limit is limited to MODES 1 and 2.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a degraded core accident would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the hydrogen igniter is low. Therefore, the hydrogen igniter is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a degraded core accident are reduced due to the pressure and temperature limitations. Therefore, the hydrogen igniters are not required to be OPERABLE in MODES 4 and 5 to control hydrogen.

ACTIONS

A.1

With one hydrogen igniter division inoperable, the inoperable division must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE hydrogen igniter division is adequate to perform the hydrogen burn function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding, the amount of time available after the event for operator action to prevent hydrogen

(continued)

BASES

ACTIONS

A.1 (continued)

accumulation from exceeding the flammability limit, and the low probability of failure of the OPERABLE hydrogen igniter division.

B.1 and B.2

With two primary containment and drywell hydrogen igniter divisions inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by at least one primary containment hydrogen recombiner and one combustible gas mixing subsystem. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control capabilities. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control capabilities. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two igniter divisions inoperable for up to 7 days. Seven days is a reasonable time to allow two igniter divisions to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

BASES

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time cannot be 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1 and SR 3.6.3.2.2

These SRs verify that there are no physical problems that could affect the hydrogen igniter operation. Since the hydrogen igniters are mechanically passive, they are not subject to mechanical failure. The only credible failures are loss of power or burnout. The verification that each required hydrogen igniter is energized is performed by circuit current versus voltage measurement.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.2.3 and SR 3.6.3 2.4

These functional tests are performed to verify system OPERABILITY. The current draw to develop a surface temperature of ≥ 1700°F is verified for hydrogen igniters in inaccessible areas, e.g., in a high radiation area. Additionally, the surface temperature of each accessible hydrogen igniter is measured to be ≥ 1700°F to demonstrate that a temperature sufficient for ignition is achieved. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. USAR, Section 6.2.8.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 Combustible Gas Mixing System

BASES

BACKGROUND

The Combustible Gas Mixing System ensures a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The Combustible Gas Mixing System is an Engineered Safety Feature and is designed to operate following a loss of coolant accident (LOCA) in post accident environments without loss of function. There are two redundant and independent combustible gas mixing subsystems, each consisting of a compressor and associated valves, controls, and piping. Each combustible gas mixing subsystem is sized to pump 500 scfm. Each subsystem is powered from a separate emergency power supply. Since each combustible gas mixing subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

Following a LOCA, the drywell is immediately pressurized due to the release of steam into the drywell environment. This pressure is relieved by the lowering of the water level within the weir wall, clearing the horizontal vents and allowing the mixture of steam and noncondensibles to flow into the primary containment through the suppression pool, removing much of the heat from the steam. The remaining steam in the drywell begins to condense. As steam flow from the reactor pressure vessel ceases, the drywell pressure falls rapidly. The combustible gas mixing compressors are manually started prior to the drywell hydrogen concentration exceeding 3.0 v/o. The compressors force air from the primary containment into the drywell. Drywell pressure increases until the water level between the weir wall and the drywell is forced down to the horizontal pool vents forcing drywell atmosphere back into containment and mixing with containment atmosphere to dilute the hydrogen. While combustible gas mixing continues following the LOCA, hydrogen continues to be produced. Eventually, the 4.0 v/o limit is again approached and the primary containment hydrogen recombiners are manually placed in operation.

(continued)

BASES

BACKGROUND (continued)

The containment spray is credited with removal of airborne radionuclides. Post-LOCA operation of the mixing compressors also provides a transport of air between containment and the drywell. Therefore, post-LOCA dose is reduced with mixing compressor operation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The Combustible Gas Mixing System provides the capability for reducing the drywell hydrogen concentration to approximately the bulk average primary containment concentration following a Design Basis Accident (DBA). The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; and

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with plant procedures, the peak hydrogen concentration in the primary containment remains < 4.0 v/o.

The Combustible Gas Mixing System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Two combustible gas mixing subsystems must be OPERABLE to ensure operation of at least one primary containment combustible gas mixing subsystem in the event of a worst case single active failure. Operation with at least one OPERABLE combustible gas mixing subsystem provides the capability of controlling the hydrogen concentration in the drywell without exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the two combustible gas mixing subsystems ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.0 v/o in the drywell, assuming a worst case single active failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that

(continued)

BASES

APPLICABILITY (continued)

calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the Combustible Gas Mixing System is low. Therefore, the Combustible Gas Mixing System is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, the Combustible Gas Mixing System is not required in these MODES.

ACTIONS

A.1

With one combustible gas mixing subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the hydrogen mixing function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in reduced hydrogen mixing capability. The 30 day Completion Time is based on the low probability of failure of the OPERABLE combustible gas mixing subsystem, the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, and the amount of time available after the event for operator action to prevent hydrogen accumulation from exceeding this limit.

B.1 and B.2

With two combustible gas mixing subsystems inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by one primary containment hydrogen recombiner or one division of the hydrogen

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

igniters. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control capabilities. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control capabilities. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two combustible gas mixing subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two combustible gas mixing subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit.

C.1

If any Required Action and associated Completion Time cannot be 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

Operating each combustible gas mixing subsystem for ≥ 15 minutes after starting from the control room ensures that each subsystem is OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, compressor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3.2

Verifying that each combustible gas mixing subsystem flow rate is ≥ 500 scfm ensures that each subsystem is capable of maintaining drywell hydrogen concentrations below the flammability limit. Analysis has shown that satisfying this surveillance requirement also verifies that the compressor can deliver ≥ 500 scfm under post-LOCA conditions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Regulatory Guide 1.7, Revision 2.
2. USAR, Section 6.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Annulus Exhaust Gas Treatment (AEGT) System and manual closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, such as during movement of recently irradiated fuel assemblies in the primary containment.

The secondary containment is a structure that completely encloses the primary containment. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the external pressure. To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Annulus Exhaust Gas Treatment (AEGT) System."

The isolation devices for the penetrations in the secondary containment boundary are a part of the secondary containment barrier. To maintain this barrier:

a. All penetrations terminating in the secondary containment required to be closed during accident conditions are closed by at least one manual valve or blind flange, as applicable, secured in its closed position, except as provided in LCO 3.6.4.2, “Secondary Containment Isolation Valves (SCIVs)”;

(continued)

BASES

BACKGROUND (continued)

b. The containment equipment hatch is closed and sealed and the shield blocks are installed adjacent to the shield building;

c. The door in each access to the secondary containment is closed, except for entry and exit;

d. The sealing mechanism associated with each shield building penetration, e.g. welds, bellows, or O-rings, is functional;

e. The pressure within the secondary containment is less than or equal to the value required by Surveillance Requirement SR 3.6.4.1.1, except for entry and exit to the annulus; and

f. The Annulus Exhaust Gas Treatment System is OPERABLE.

APPLICABLE SAFETY ANALYSES

There is one accident for which credit is taken for secondary containment OPERABILITY. This is a LOCA (Ref. 1). The secondary containment performs no active function in response to this limiting event; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis, and that fission products entrapped within the secondary containment structure will be treated by the AEGT System prior to discharge to the environment.

Secondary containment satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit secondary containment. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit secondary containment during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

(continued)

BASES (continued)

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, handling of fuel only requires OPERABILITY of Secondary Containment when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABLITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 2).

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the secondary 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 12 hours and to MODE 4 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

ACTIONS (continued)

C.1

Movement of recently irradiated fuel assemblies in the primary containment can be postulated to cause significant fission product releases. In such cases, the secondary containment is one of the barriers to release of fission products to the environment. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended if the secondary containment is inoperable. Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions.

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

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that the primary containment equipment hatch is closed and the shield blocks are installed adjacent to the shield building, and secondary containment access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. In this application, the term "sealed" has no connotation of leak tightness. Verifying that all such openings are closed provides adequate

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3 6.4.1.2 and SR 3.6.4.1.3 (continued) assurance that exfiltration from the secondary containment will not occur. Maintaining secondary containment OPERABILITY requires verifying each door in both access openings are closed, except when the access opening is being used for entry and exit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.6.5. 2. USAR, Section 15.7.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND	The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Isolation barrier(s) for the penetration are discussed in Reference 2. The isolation devices addressed by this LCO are passive. Manual valves and blind flanges are considered passive devices. Penetrations are isolated by the use of manual valves in the closed position or blind flanges.
APPLICABLE SAFETY ANALYSES	The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accident for which the secondary containment boundary is required is a loss of coolant accident (Ref. 1). The secondary containment performs no active function in response to this limiting event, but the boundary established by SCIVs is required to ensure that leakage from the primary containment is processed by the Annulus Exhaust Gas Treatment (AEGT) System before being released to the environment. Maintaining SCIVs OPERABLE ensures that fission products will remain trapped inside secondary containment so that they can be treated by the AEGT System prior to discharge to the environment. SCIVs satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the secondary containment. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the secondary containment during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed, or open in accordance with appropriate administrative controls, or blind flanges are in place. The valves covered by this LCO are included in Table B 3.6.4.2-1.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, handling of fuel only requires OPERABILITY of secondary containment isolation valves when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 3).

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the

(continued)

BASES

ACTIONS (continued)

penetration can be rapidly isolated when the need for secondary containment isolation is indicated.

The second Note provides clarification that, for the purpose of 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 SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS (continued)

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

The term "penetration" refers to piping/ductwork lines that pass through the secondary containment boundary; these lines are isolable by SCIVs. This use of the term is separate and distinct from the Civil/Structural term "penetration" used to describe the larger opening that multiple lines may pass through and which is sealed by welded steel plate or environmentally qualified material everywhere except where the lines pass through. When an SCIV becomes inoperable within a line, and the Required Action directs the operator to "isolate the affected penetration flowpath", the intent is to isolate only the line with the inoperable SCIV. It is not the intent to close off the other lines that are unaffected by the inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one valve inoperable, the affected penetration flow path(s) 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 manual valve or a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. This Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration and the low probability of a DBA occurring during this short time. For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, will be isolated should an event occur. This Required Action does not require any testing or isolation device manipulation. Rather, it involves verification that these isolation devices capable of being mispositioned are in the correct position. The Completion Time for this verification of "once per 31 days" is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low.

(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 them to be verified by use of administrative controls. Allowing verification by administrative controls 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 low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. 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 manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the low probability of a DBA occurring during this short time.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B cannot be met in MODE 1, 2, or 3, 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 12 hours and to MODE 4 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.

D.1

If any Required Action and associated Completion Time of Condition A or B cannot be met during movement of recently irradiated fuel assemblies in the primary containment,

(continued)

BASES

ACTIONS

D.1 (continued)

the plant must be placed in a condition in which the LCO does not apply. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is 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 secondary containment boundary is within design limits. This SR does not require any testing or isolation device manipulation. Rather, it involves verification that those isolation devices in secondary containment that are capable of being mispositioned are in the correct position.

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

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these isolation devices once they have been verified to be in the proper position, is low. A second Note has been included to clarify that

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.4.2.1</u> (continued) that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.
REFERENCES	1. USAR, Section 15.6.5. 2. USAR, Section 6.2.3. 3. USAR, Section 15.7.6.

BASES

Table B 3.6.4.2-1 (page 1 of 1)

Secondary Containment Isolation Valves

1P53-F534

1E61-D002

1E61-F529

1E61-F530

1E61-F531

1E61-F532

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Annulus Exhaust Gas Treatment (AEGT) System

BASES

BACKGROUND

The AEGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the AEGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The AEGT System consists of two independent and redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A demister;

b. A roughing filter;

c. Deleted.

d. A high efficiency particulate air (HEPA) filter;

e. A charcoal adsorber;

f. A second HEPA filter; and

g. A centrifugal fan with motor operated control dampers.

The sizing of the AEGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment structure. The internal pressure of the AEGT System boundary region is maintained at a negative pressure of 0.25 inch water gauge when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building when exposed to a 30 mph wind.

The demister is provided to remove entrained water in the air.

(continued)

BASES

BACKGROUND (continued)	The roughing filter removes large particulate matter, while the HEPA filter is provided to remove fine particulate matter and protect the charcoal from fouling. The charcoal adsorber is not credited in the loss of coolant accident analysis (Ref. 3). The final HEPA filter is provided to collect any carbon fines exhausted from the charcoal adsorber. The AEGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. AEGT System flows are controlled by two motor operated control dampers installed in branch ducts. One duct exhausts air to the unit vent, (AEGT Subsystem A exhausts to the Unit 1 plant vent; AEGT Subsystem B exhausts to the Unit 2 plant vent), while the other recirculates air back to the annulus.
APPLICABLE SAFETY ANALYSES	The design basis for the AEGT System is to mitigate the consequences of a loss of coolant accident. For all events analyzed, the AEGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment. The AEGT System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the AEGT System. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the AEGT System during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.
LCO	Following a DBA, a minimum of one AEGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two independent operable subsystems ensures operation of at least one AEGT subsystem in the event of a single active failure.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, AEGT System OPERABILITY is required during these MODES.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the AEGT System OPERABLE is not required in MODE 4 or 5, except for

(continued)

BASES

APPLICABILITY (continued)

other situations under which significant releases of radioactive material can be postulated, such as during movement of recently irradiated fuel assemblies in the primary containment. Due to radioactive decay, handling of fuel only requires OPERABILITY of the AEGT System when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 5).

ACTIONS

A.1

With one AEGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE AEGT subsystem is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single failure in the OPERABLE subsystem could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant AEGT subsystem and the low probability of a DBA occurring during this period.

B.1 and B.2

If the AEGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 12 hours and to MODE 4 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

During movement of recently irradiated fuel assemblies in the primary containment, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE AEGT subsystem should be immediately placed in operation. This Required Action ensures that the remaining subsystem is OPERABLE, that no

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected. An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing significant amounts of radioactive material, thus placing the unit in a Condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

D.1

If both AEGT subsystems are inoperable in MODE 1, 2, or 3, the AEGT System may not be capable of supporting the required radioactivity release control function. Therefore, LCO 3.0.3 must be entered immediately.

E.1

When two AEGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in the primary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each AEGT subsystem from the control room for ≥ 15 continuous minutes ensures that both subsystems are OPERABLE and that all associated controls are functioning properly (Ref. 4). It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1 (continued)

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

SR 3.6.4.3.2

This SR verifies that the required AEGT filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The AEGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter efficiency, system flow rate, and general operating parameters of the filtration system. (Note: Values identified in the VFTP are Surveillance Requirement values.) Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR verifies that each AEGT subsystem starts and isolation dampers open upon receipt of a manual initiation signal from the control room and an actual or simulated initiation and operates throughout its emergency operating sequence for the LOCA signal. The SR excludes automatic dampers that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to dampers that are locked, sealed, or otherwise secured in the actuated position since the affected dampers were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic 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 damper to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic damper to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function. This Surveillance can be performed with the reactor at power. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.
2. USAR, Section 6.5.3.
3. USAR, Section 15.6.5.
4. Regulatory Guide 1.52, Rev. 4.
5. Deleted.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.1 Drywell

BASES

BACKGROUND

The drywell houses the reactor pressure vessel (RPV), the reactor coolant recirculating loops, and branch connections of the Reactor Coolant System (RCS), which have isolation valves at the primary containment boundary. The function of the drywell is to maintain a pressure boundary that channels steam from a loss of coolant accident (LOCA) to the suppression pool, where it is condensed. Air forced from the drywell is released into the primary containment through the suppression pool. The pressure suppression capability of the suppression pool assures that peak LOCA temperature and pressure in the primary containment are within design limits. The drywell also protects accessible areas of the containment from radiation originating in the reactor core and RCS.

To ensure the drywell pressure suppression capability, the drywell bypass leakage must be minimized to prevent overpressurization of the primary containment during the drywell pressurization phase of a LOCA. This requires periodic testing of the drywell bypass leakage, confirmation that the drywell air lock is leak tight, OPERABILITY of the drywell isolation valves, confirmation that the drywell equipment head is closed and sealed, confirmation that the drywell head is installed and sealed, and confirmation that the drywell vacuum relief valves are closed.

The drywell air lock forms part of the drywell pressure boundary. Not maintaining air lock OPERABILITY may result in degradation of the pressure suppression capability, which is assumed to be functional in the unit safety analyses. The drywell air lock does not need to meet the requirements of 10 CFR 50, Appendix J (Ref. 1), since it is not part of the primary containment leakage boundary. However, it is prudent to specify a leakage rate requirement for the drywell air lock. A seal leakage rate limit and a barrel leakage rate limit have been established in plant procedures to assure the integrity of the air lock.

The isolation devices for the drywell penetrations are a part of the drywell barrier. To maintain this barrier:

(continued)

BASES

BACKGROUND (continued)

a. The drywell air lock is OPERABLE except as provided in LCO 3.6.5.2, "Drywell Air Lock";

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

   1. capable of being closed by an OPERABLE automatic drywell isolation valve, or

   2. closed by a manual valve, blind flange, or de-activated automatic valve secured in the closed position except as provided in LCO 3.6.5.3, "Drywell Isolation Valves";

(continued)

BASES

BACKGROUND (continued)

c. The drywell equipment hatch is closed and sealed;

d. The drywell head is installed and sealed;

e. The Drywell Vacuum Relief System is OPERABLE except as provided in LCO 3.6.5.6, "Drywell Vacuum Relief System";

f. The drywell leakage rates are within the limits of SR 3.6.5.1.1;

g. The suppression pool is OPERABLE; and

h. The sealing mechanism associated with each drywell penetration, e.g., welds, bellows, or O-rings, is functional.

This Specification is intended to ensure that the performance of the drywell in the event of a DBA meets the assumptions used in the safety analyses (Ref. 1).

APPLICABLE SAFETY ANALYSES

Analytical methods and assumptions involving the drywell are presented in Reference 1. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Maintaining the pressure suppression capability assures that safety analyses remain valid and that the peak LOCA temperature and pressure in the primary containment are within design limits.

The drywell satisfies Criteria 2 and 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Maintaining the drywell OPERABLE is required to ensure that the pressure suppression design functions assumed in the safety analyses are met. The drywell is OPERABLE if the drywell structural integrity is intact and the bypass leakage is within limits, except prior to the first startup after performing a required drywell bypass leakage test. At this time, the drywell bypass leakage must be ≤ 10% of the drywell bypass leakage limit.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the drywell is not required to be OPERABLE in MODES 4 and 5.

ACTIONS

A.1

In the event the drywell is inoperable, it 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 the drywell OPERABLE during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring drywell OPERABILITY) occurring during periods when the drywell is inoperable is minimal. Also, the Completion Time is the same as that applied to inoperability of the primary containment in LCO 3.6.1.1, "Primary Containment - Operating."

B.1 and B.2

If the drywell 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 12 hours and to MODE 4 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 3.6.5.1.1

The analyses in Reference 1 are based on a maximum drywell bypass leakage. Testing shall be conducted at an initial differential pressure of 2.5 psi and the $A/\sqrt{k}$ shall be calculated from the measured leakage. One drywell air lock door shall remain open during the drywell leakage test such that each drywell air lock door is leak tested during at least every other leakage rate test.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.1 (continued)

This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable $A/\sqrt{k}$ design value of 1.68 ft^2 assumed in the safety analysis. As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be ≤ 10% of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design $A/\sqrt{k}$. At the design $A/\sqrt{k}$ the containment temperature and pressurization response are bounded by the assumptions of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If during the performance of this required Surveillance the drywell bypass leakage is greater than the leakage limit, the Surveillance Frequency is increased to every 48 months. If during the performance of the subsequent consecutive Surveillance the drywell bypass leakage is less than or equal to the drywell bypass leakage limit, the Frequency specified in the Surveillance Frequency Control Program may be resumed. If during the performance of the subsequent consecutive Surveillance the drywell bypass leakage is greater than the drywell bypass leakage limit, the Surveillance Frequency is increased to at least once every 24 months. The 24 month Frequency will be maintained until during the performance of two consecutive Surveillances the drywell bypass leakage is less than or equal to the leakage limit, at which time the Frequency specified in the Surveillance Frequency Control Program may be resumed. For two Surveillances to be considered consecutive, the Surveillances must be performed at least 12 months apart.

SR 3.6.5.1.2

The exposed accessible drywell interior and exterior surfaces are inspected to ensure there are no apparent physical defects that would prevent the drywell from performing its intended function. This SR ensures that

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.2 (continued)

drywell structural integrity is maintained. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.5.1.3

This SR requires a test to be performed to quantify seal leakage of the drywell air lock doors at pressures ≥ 2.5 psig. An administrative seal leakage rate limit has been established in plant procedures to ensure the integrity of the seals.

The Surveillance is only required to be performed once within 72 hours after each closing. The Frequency of 72 hours is based on operating experience and is considered adequate in view of the other indications available to plant operations personnel that the seal is intact.

SR 3.6.5.1.4

This SR requires a test to be performed to quantify air lock barrel leakage at pressures ≥ 2.5 psig. An administrative barrel leakage rate limit has been established in plant procedures to ensure the integrity of the air lock.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.4 (continued)

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

This SR has been modified by a Note indicating that an inoperable air lock door does not invalidate the previous successful performance of an overall (barrel) 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.

REFERENCES

1. USAR, Chapter 6 and Chapter 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.2 Drywell Air Lock

BASES

BACKGROUND

The drywell air lock forms part of the drywell boundary and provides a means for personnel access. For this purpose, one double door drywell air lock has been provided, which maintains drywell isolation during personnel entry and exit from the drywell. Each of the doors has inflatable seals that are maintained ≥ 60 psig by the Service and Instrument Air System, which is maintained at a pressure of ≥ 120 psig. Each door has two seals to ensure they are single failure proof in maintaining the drywell boundary.

The drywell air lock is designed to the same standards as the drywell boundary. Thus, the drywell air lock must withstand the pressure and temperature transients associated with the rupture of any primary system line inside the drywell and also the rapid reversal in pressure when the steam in the drywell is condensed by the Emergency Core Cooling System flow following loss of coolant accident flooding of the reactor pressure vessel (RPV). It is also designed to withstand the high temperature associated with the break of a small steam line in the drywell that does not result in rapid depressurization of the RPV.

The air lock is nominally a right circular cylinder with doors at each end that are interlocked to prevent simultaneous opening. During periods when the drywell is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent drywell 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).

The air lock is provided with limit switches on both doors that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever both air lock doors are simultaneously open.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the drywell are presented in Reference 2. The safety analyses assume that for a high energy line break inside the drywell, the steam is directed to the suppression pool through the horizontal vents where it is condensed. Since the drywell air lock is part of the drywell pressure boundary, its design and maintenance are essential to support drywell OPERABILITY, which assures that the safety analyses are met. The drywell air lock satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The drywell air lock forms part of the drywell pressure boundary. The air lock safety function assures that steam resulting from a DBA is directed to the suppression pool. Thus, the air lock's structural integrity is essential to the successful mitigation of such an event. The drywell air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of the drywell does not exist when the drywell is required to be OPERABLE. Air lock leakage is excluded from this specification. The air lock leakage rate is part of the drywell leakage rate and is controlled as part of OPERABILITY of the drywell in LCO 3.6.5.1. Closure of a single door in the air lock is sufficient to support drywell OPERABILITY following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for entry into and exit from the drywell.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the drywell air lock is not required to be OPERABLE in MODES 4 and 5.

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs of the affected air lock components. If the outer door is inoperable, then it may be easily accessed for most repairs. If the inner door is inoperable, however, then there is a short time during which the drywell boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the drywell boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the drywell during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

<u>A.1, A.2, and A.3</u>

With one drywell air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1). This ensures that a leak tight drywell barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1 which requires that the drywell be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time (Required Action A.2). The Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

Required Action A.3 verifies that the air lock with an inoperable door has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable drywell 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. Allowing verification by administrative controls 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 are 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 air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 provide the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Times 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.

Drywell entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside the drywell that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the drywell was entered, using the inoperable air lock, to perform an allowed activity listed above. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the OPERABLE door except during the entry and exit, and assuring the OPERABLE door is relocked after completion of the drywell entry and exit. This allowance is acceptable due to the low probability of an event that could pressurize the drywell during the short time that the OPERABLE door is expected to be open.

(continued)

ACTIONS (continued)

B.1, B.2, and B.3

With the drywell air lock interlock mechanism inoperable, the Required Actions and associated Completion Times are consistent with these specified in Condition A. The Required Actions are 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 air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 provide the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Times from the initial entry into Condition B, only the requirement to comply with Required Actions. Note 2 allows entry into and exit from the drywell 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). Allowing verification by administrative controls 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 and C.2

With the drywell air lock inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires that one door in the drywell air lock must be verified closed. This Required Action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.5.1, which requires that the drywell be restored to OPERABLE status within 1 hour.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status, considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable drywell 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 12 hours and to MODE 4 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 3.6.5.2.1

Deleted

SR 3.6.5.2.2

The Service and Instrument Air System pressure in the header to the drywell air lock is periodically verified to be ≥ 60 psig to ensure that the seal system remains viable. It must be checked because it could bleed down during or following access through the air lock, which occurs regularly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.5.2.3

The air lock door interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of the air lock are designed to withstand the maximum expected post accident drywell pressure, closure of either door will support drywell OPERABILITY. Thus, the door interlock feature supports drywell OPERABILITY while the air lock is being used for personnel transit in and out of the drywell. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Surveillance is modified by a Note requiring the Surveillance to be performed only upon entry into the drywell.

SR 3.6.5.2.4

Deleted

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.6.5.2.5 A seal pneumatic system test to ensure that pressure does not decay at a rate equivalent to > 3 psig for a period of 24 hours from an initial pressure of 60 psig is an effective leakage rate test to verify system performance. The 24 hour interval is based on engineering judgment, considering that there is no postulated DBA where the drywell is still pressurized 24 hours after the event. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50, Appendix J. 2. USAR, Chapters 6 and 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.3 Drywell Isolation Valves

BASES

BACKGROUND

The drywell isolation valves, in combination with other accident mitigation systems, ensure that steam and water releases to the drywell are channeled to the suppression pool to maintain the pressure suppression function of the drywell.

The OPERABILITY requirements for drywell isolation valves help ensure that an adequate drywell boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements support minimizing drywell bypass leakage assumed in the safety analysis (Ref. 1) for a DBA. Typically, two barriers in series are provided for each penetration so that no credible single failure or malfunction of an active component can result in a loss of isolation. The isolation devices addressed by this LCO are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position, check valves with flow through the valve secured, and blind flanges are considered passive devices. Check valves and automatic valves designed to close without operator action following an accident, are considered active devices.

The Drywell Vacuum Relief System valves serves a dual function, one of which is drywell isolation. However, since the other safety function of vacuum relief would not be available if the normal drywell isolation valve ACTIONS were taken, the drywell isolation valve OPERABILITY requirements are not applicable to the drywell vacuum relief subsystem isolation valves. Similar surveillance requirements provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The drywell purge supply subsystem and the drywell purge exhaust portion of the containment and drywell purge exhaust subsystem is a high capacity system with 24 and 36 inch lines, which have isolation valves covered by this LCO. The system supplies air from primary containment to the drywell through two lines, each containing a fan and two drywell isolation valves called drywell purge supply isolation

(continued)

BASES

BACKGROUND (continued)	valves. The drywell air is exhausted through a line also containing two drywell purge exhaust isolation valves and is then exhausted into the exhaust portion of the Containment Vessel and Drywell Purge System. The system is used to remove trace radioactive airborne products prior to personnel entry. The drywell purge mode is not used in MODE 1, 2, or 3; therefore, the drywell purge supply and exhaust isolation valves are sealed shut during power operation.
APPLICABLE SAFETY ANALYSES	This LCO is intended to ensure that releases from the core do not bypass the suppression pool so that the pressure suppression capability of the drywell is maintained. Therefore, as part of the drywell boundary, drywell isolation valve OPERABILITY minimizes drywell bypass leakage. Therefore, the safety analysis of any event requiring isolation of the drywell is applicable to this LCO. The limiting DBA resulting in a release of steam, water, or radioactive material within the drywell is a LOCA. In the analysis for this accident, it is assumed that drywell isolation valves are either closed or function to close within the required isolation time following event initiation. The drywell isolation valves and drywell purge supply and exhaust isolation valves satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The drywell isolation valve safety function is to form a part of the drywell boundary. The power operated drywell isolation valves are required to have isolation times within limits. Power operated automatic drywell isolation valves are also required to actuate on an automatic isolation signal. Additionally, drywell purge supply and exhaust isolation valves are required to be closed. While the Drywell Vacuum Relief System valves isolate drywell penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.5.6, "Drywell Vacuum Relief System."

(continued)

BASES

LCO (continued)

Drywell isolation valve leakage is also excluded from this Specification. The drywell isolation valve leakage rates are part of the drywell leakage rate and are controlled as part of OPERABILITY of the drywell in LCO 3.6.5.1.

The normally closed drywell isolation valves or blind flanges are considered OPERABLE when, as applicable, manual valves are closed or opened in accordance with applicable administrative controls, automatic valves are de-activated and secured in their closed position, check valves with flow through the valve secured, or blind flanges are in place. The valves covered by this LCO are included (with their associated stroke time, if applicable, for automatic valves) in Table B 3.6.5.3-1.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the drywell isolation valves are not required to be OPERABLE in MODES 4 and 5.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths, except for the 24 and 36 inch purge supply and exhaust valve penetration flow paths, to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated when a need for drywell isolation is indicated.

The second Note provides clarification that, for the purpose of 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 drywell isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable drywell isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The third Note requires the OPERABILITY of affected systems to be evaluated when a drywell isolation valve is inoperable. This ensures appropriate remedial actions are

(continued)

BASES

ACTIONS (continued)

taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable drywell isolation valve.

Pursuant to LCO 3.0.6, these ACTIONS are not required even when the associated LCO is not met. Therefore, Note 3 is added to require the proper actions to be taken. The term "penetration" refers to piping/ductwork lines that pass through the drywell boundary; these lines are isolable by automatic isolation valves. This use of the term is separate and distinct from the Civil/Structural term "penetration" used to describe the larger opening that multiple lines may pass through and which is sealed by welded steel plate or environmentally qualified material everywhere except where the lines pass through. When a drywell isolation valve becomes inoperable within a line, and the Required Action directs the operator to "isolate the affected penetration flowpath", the intent is to isolate only the line with the inoperable drywell isolation valve. It is not the intent to close off other lines that are unaffected by the inoperable valve.

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

With one or more penetration flow paths with one drywell isolation valve inoperable, 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 manual valve, a closed and de-activated automatic valve, a check valve with flow through the valve secured, and a blind flange. The 8 hour Completion Time is acceptable, due to the low probability of the inoperable valve resulting in excessive drywell leakage and the low probability of the limiting event for drywell leakage occurring during this short time frame. In addition, the Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting drywell OPERABILITY during MODES 1, 2, and 3.

For affected penetration flow paths 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 drywell penetrations that are required to be isolated following an accident, and are no longer capable of being automatically

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

isolated, will be isolated should an event occur. This Required Action does not require any testing or isolation device manipulation. Rather, it involves verification that those devices outside drywell and capable of being mispositioned are in the correct position. Since these isolation devices are inside primary containment, the specified time period of "prior to entering MODE 2 or 3 from MODE 4, 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 the existence of other administrative controls, ensuring that isolation device misalignment is an unlikely possibility. Also, this Completion Time is consistent with the Completion Time specified for PCIVs in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)."

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls 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 lqocking, 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 low.

B.1

With one or more penetration flow paths with two drywell isolation valves inoperable, 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 manual valve, a closed and de-activated automatic valve, a check valve with flow through the valve secured, and a blind flange. The 4 hour Completion Time is acceptable due to the low probability of the inoperable valves resulting in excessive drywell leakage and the low probability of the limiting event for drywell leakage occurring during this short time frame. The Completion Time is reasonable, considering the time required to isolate the penetration, and the probability of a DBA, which requires the drywell isolation valves to close, occurring during this short time is very low.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 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 3.6.5.3.1

Each 24 (1M14-F055 A (B) and 1M14-F060 A (B)) and 36 inch (1M14-F065 and 1M14-F070) drywell purge supply and exhaust isolation valve is required to be periodically verified sealed closed because the drywell purge supply and exhaust isolation valves are not qualified to fully close under accident conditions. This SR is designed to ensure that a gross breach of drywell is not caused by an inadvertent drywell purge supply or exhaust isolation valve opening. Detailed analysis of these 24 and 36 inch drywell purge supply and exhaust isolation valves failed to conclusively demonstrate their ability to close during a LOCA in time to support drywell OPERABILITY. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, and 3. These 24 and 36 inch drywell purge supply and exhaust isolation valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power, removing the air supply to the valve operator, or providing administrative control of the valve control switches. In this application, the term "sealed" has no connotation of leak tightness. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.5.3.2

Deleted

SR 3.6.5.3.3

This SR verifies that each drywell isolation manual valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that drywell bypass leakage is maintained to a minimum. Due to

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.3.3 (continued)

the location of these isolation devices, the Frequency specified as "prior to entering MODE 2 or 3 from MODE 4, if not performed in the previous 92 days," is appropriate because of the inaccessibility of the devices and because these devices are operated under administrative controls and the probability of their misalignment is low. 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.

Two Notes are added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted during MODES 1, 2, and 3. Therefore, the probability of misalignment of these isolation devices, once they have been verified to be in their proper position, is low. A second Note is included to clarify that the drywell isolation valves that are open under administrative controls are not required to meet the SR during the time that the drywell isolation valves are open.

SR 3.6.5.3.4

Verifying that the isolation time of each power operated and each automatic drywell isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the drywell isolation valve will isolate in a time period less than or equal to that assumed in the safety analysis. The isolation time and Frequency of this SR are in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.5.3.5

Verifying that each automatic drywell isolation valve closes on a drywell isolation signal is required to prevent bypass leakage from the drywell following a DBA. This SR ensures each automatic drywell isolation valve will actuate to its isolation position on a drywell isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.5 overlaps this SR to provide complete testing of the safety function.

(continued)

BASES

SURVEILLANCE REQUIREMENT	SR 3.6.5.3.5 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 6.2.1.1.5.

BASES

Table B 3.6.5.3-1 (page 1 of 1)
Drywell Isolation Valves

Valve Number	Maximum Isolation Time (seconds)
1B33-F013A	NA
1B33-F013B	NA
1B33-F017A	NA
1B33-F017B	NA
1B33-F019	5
1B33-F020	5
1C41-F006	NA
1C41-F007	NA
1G61-F030	22
1G61-F035	22
1G61-F150	22
1G61-F155	22
1M14-F055A	4
1M14-F055B	4
1M14-F060A	4
1M14-F060B	4
1M14-F065	4
1M14-F070	4
1M51-F010A	37
1M51-F010B	37
1P22-F015	18.8
1P22-F593	NA
1P43-F355	15
1P43-F400	15
1P43-F410	15
1P43-F722	NA
1P51-F652	22.5
1P51-F653	NA
1P52-F639	NA
1P52-F646	30*
1P54-F395	20*

* Standard closure time, based on nominal pipe diameter, is approximately 12 inches per minute for gate valves and approximately four inches per minute for globe valves.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.4 Drywell Pressure

BASES

BACKGROUND

Drywell-to-primary containment differential pressure is an assumed initial condition in the analyses that determine the primary containment thermal hydraulic and dynamic loads during a postulated loss of coolant accident (LOCA).

If drywell pressure is less than the primary containment airspace pressure, the water level in the weir annulus will increase and, consequently, the liquid inertia above the top vent will increase. This will cause top vent clearing during a postulated LOCA to be delayed, and that would increase the peak drywell pressure. In addition, an inadvertent upper pool dump occurring with a negative drywell-to-primary containment differential pressure could result in overflow over the weir wall.

The limitation on negative drywell-to-primary containment differential pressure ensures that changes in calculated peak LOCA drywell pressures due to differences in water level of the suppression pool and the drywell weir annulus are negligible. It also ensures that the possibility of weir wall overflow after an inadvertent upper pool dump is minimized. The limitation on positive drywell-to-primary containment differential pressure helps ensure that the horizontal vents are not cleared with normal weir annulus water level.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. Among the inputs to the design basis analysis is the initial drywell internal pressure (Ref. 1). The initial drywell internal pressure affects the drywell pressure response to a LOCA (Ref. 1) and the suppression pool swell load definition (Ref. 2).

Additional analyses (Refs. 3 and 4) have been performed to show that if initial drywell pressure does not exceed the negative pressure limit, the suppression pool swell and vent clearing loads will not be significantly increased and the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	probability of weir wall overflow is minimized after an inadvertent upper pool dump. Drywell pressure satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	A limitation on the drywell-to-primary containment differential pressure of ≥ -0.5 psid and ≤ 2.0 psid is required to ensure that suppression pool water is not forced over the weir wall, vent clearing does not occur during normal operation, containment conditions are consistent with the safety analyses, and LOCA drywell pressures and pool swell loads are within design values.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining the drywell-to-primary containment differential pressure limitation is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With drywell-to-primary containment differential pressure not within the limits of the LCO, it must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.5.1, "Drywell," which requires that the drywell be restored to OPERABLE status within 1 hour. <u>B.1 and B.2</u> If drywell-to-primary containment differential 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 12 hours and

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

to MODE 4 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 3.6.5.4.1

This SR provides assurance that the limitations on drywell-to-primary containment differential pressure stated in the LCO are met. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 6.2.1.
2. USAR, Section 3.8.
3. USAR, Section 6.2.1.1.6.
4. USAR, Section 6.2.7.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.5 Drywell Air Temperature

BASES

BACKGROUND	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell air coolers remove heat and maintain a suitable environment. The drywell average air temperature affects equipment OPERABILITY, personnel access, and the calculated response to postulated Design Basis Accidents (DBAs). The limitation on drywell average air temperature ensures that the peak drywell temperature during a design basis loss of coolant accident (LOCA) does not exceed the design temperature of 330°F. The limiting DBA for drywell atmosphere temperature is a small steam line break, assuming no heat transfer to the passive steel and concrete heat sinks in the drywell.
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs inside containment (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature. Increasing the initial drywell average air temperature could change the calculated results of the design bases analysis. The safety analyses (Ref. 1) assume an initial average drywell air temperature of 145°F. This limitation ensures that the safety analyses remain valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 330°F. The consequence of exceeding this design temperature may result in the degradation of the drywell structure under accident loads. Equipment inside the drywell that is required to mitigate the effects of a DBA is designed and qualified to operate under environmental conditions expected for the accident. Drywell average air temperature satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	If the initial drywell average air temperature is less than or equal to the LCO temperature limit, the peak accident temperature can be maintained below the drywell design

(continued)

BASES

LCO (continued)	temperature during a DBA. This ensures the ability of the drywell to perform its design function.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

When the drywell average air temperature is not within the limit of the LCO, it must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the safety analyses. The 8 hour Completion Time is acceptable, considering the sensitivity of the analyses to variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

If drywell average air temperature cannot be restored to within limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 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 3.6.5.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the drywell analysis. In order to determine the drywell average air temperature, an arithmetic average is calculated, using measurements taken at locations within the drywell selected to provide a representative sample of the overall drywell atmosphere.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.5.1 (continued)

	Elevation	Azimuth
a.	653'-8"	315°, 220°, 135°, 34°
b	634'-0" - 640'-0"	340°, 308°, 215°, 145°, 30°, 20°
c.	604'-6" - 609'-8"	310°, 308°, 253°, 212°, 150°, 140°, 80°

Use at least one reading from each elevation for an arithmetical average. The temperature at each elevation shall be the arithmetical average of the temperatures obtained from all available instruments at that elevation.

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

REFERENCES

1. USAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5.6 Drywell Vacuum Relief System

BASES

BACKGROUND

The Mark III pressure suppression containment is designed to condense, in the suppression pool, the steam released into the drywell in the event of a loss of coolant accident (LOCA). The steam discharging to the pool carries the noncondensibles from the drywell. Therefore, the drywell atmosphere changes from low humidity air to nearly 100% steam (no air) as the event progresses. When the drywell subsequently cools and depressurizes, noncondensibles in the drywell must be replaced. The drywell vacuum relief subsystems are the means by which noncondensibles are transferred from the primary containment back to the drywell.

The Drywell Vacuum Relief System is a potential source of drywell bypass leakage (i.e., some of the steam released into the drywell from a LOCA bypasses the suppression pool and leaks directly to the primary containment airspace). Since excessive drywell bypass leakage could degrade the pressure suppression function, the Drywell Vacuum Relief System has been designed with two valves in series in each vacuum breaker line. This minimizes the potential for a stuck open valve to threaten drywell OPERABILITY. The two drywell vacuum relief subsystems use separate 10 inch lines penetrating the drywell, and each subsystem consists of a series arrangement of a motor operated isolation valve and a check valve. The only safety function of the Drywell Vacuum Relief System is to provide this drywell to containment isolation.

APPLICABLE SAFETY ANALYSES

The Drywell Vacuum Relief System is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA. However, their passive operation (remaining closed and not leaking during drywell pressurization) is implicit in all of the LOCA analyses (Refs. 1 and 2).

The Drywell Vacuum Relief System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The LCO ensures that in the event of a LOCA, two drywell vacuum relief subsystems are available to mitigate the potential subsequent drywell depressurization. Each vacuum

(continued)

BASES

LCO (continued)

relief subsystem is OPERABLE when capable of opening at the required setpoint but is maintained in the closed position during normal operation (except when open during testing or when the drywell vacuum relief subsystems are performing their intended design function).

APPLICABILITY

In MODES 1, 2, and 3, a Design Basis Accident could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief System OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Drywell Vacuum Relief System OPERABLE is not required in MODE 4 or 5.

ACTIONS

The ACTIONS are modified by a Note, which ensures appropriate remedial actions are taken when necessary. Pursuant to LCO 3.0.6, ACTIONS are not required even if the drywell is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.5.1, "Drywell," when the drywell vacuum relief subsystem results in exceeding overall drywell bypass leakage rate acceptance criteria.

A.1

With one or more drywell vacuum relief subsystems open (except when open during testing or when the drywell vacuum relief subsystems are performing their intended design function), the subsystem must be closed within 4 hours. This assures that drywell leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage ($A/\sqrt{k}$) of 1.68 ft^2 is maintained, and is considered a reasonable length of time needed to complete the Required Action.

A Note has been added to provide clarification that separate Condition entry is allowed for each vacuum relief subsystem not closed.

B.1

With one drywell vacuum relief subsystem inoperable, for reasons other than Condition A, the inoperable subsystem

(continued)

BASES

ACTIONS

B.1 (continued)

must be restored to OPERABLE status within 30 days. The 30 day Completion Time takes into account a reasonable time for repairs, the low probability of an event requiring the drywell vacuum relief subsystems to function occurring during this period, and the fact that the only safety function of the Drywell Vacuum Relief System is to provide for drywell to containment isolation.

C.1

With two drywell vacuum relief subsystems inoperable, for reasons other than Condition A, at least one inoperable subsystem must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time takes into account at least one vacuum relief subsystem is still OPERABLE, a reasonable time for repairs, and the low probability of an event requiring the vacuum relief subsystems to function occurring during this period.

D.1 and D.2

If the inoperable drywell vacuum relief subsystem(s) cannot be closed or restored to OPERABLE status within the required Completion Time of Condition A, B, or C, 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 12 hours and to MODE 4 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 3.6.5.6.1

Each drywell vacuum breaker and its associated isolation valve is verified to be closed (except when being tested in accordance with SR 3.6.5.6.2 and SR 3.6.5.6.3 or when the vacuum breakers are performing their intended design function) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker or associated isolation valve

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.6.1 (continued)

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

Two Notes are added to this SR. The first Note allows drywell vacuum breakers or isolation valves opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods are controlled by plant procedures and do not represent inoperable drywell vacuum breakers or isolation valves. A second Note is included to clarify that vacuum breakers or isolation valves open due to an actual differential pressure, are not considered as failing this SR.

SR 3.6.5.6.2

Each vacuum breaker and its associated isolation valve must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This provides assurance that the safety analysis assumptions are valid. Performance of this SR includes a CHANNEL FUNCTIONAL TEST of the isolation valve actuation instrumentation.

SR 3.6.5.6.3

Verification of vacuum breaker differential pressure and associated isolation valve opening setpoint is necessary to ensure that the safety analysis assumption that the vacuum breaker will open fully at a differential pressure of 0.5 psid (containment to drywell) and that the isolation valve differential pressure actuation instrumentation opens the valve at ≤ -.810 inches water gauge dp (containment to drywell) is valid.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.5.6.3 (continued) Performance of this SR includes a CHANNEL CALIBRATION of the isolation valve actuation instrumentation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 6.2. 2. USAR, Section 7.7.1.12.

B 3.7 PLANT SYSTEMS

B 3.7.1 Emergency Service Water (ESW) System—Divisions 1 and 2

BASES

BACKGROUND

The Division 1 and Division 2 subsystems of the ESW System are designed to provide cooling water for the removal of heat from unit auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, standby diesel generators (DGs), and Emergency Closed Cooling Water (ECCW) System heat exchangers which supply cooling water to equipment required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient.

The Division 1 and 2 ESW subsystems take suction from Lake Erie and consist of two independent cooling water headers, and their associated pumps, piping, valves, and instrumentation. Any two of the three divisional ESW pumps are sized to provide sufficient cooling capacity to support the required safety related systems during safe shutdown of the unit following a loss of coolant accident (LOCA). Division 3 ESW is discussed in LCO 3.7.2, "Emergency Service Water—Division 3."

The ESW System is designed as three separate divisional subsystems, each taking suction directly from Lake Erie. Each loop is supplied by a separate pump which is operated from a preferred power source or a standby power source (diesel generator). The design of the ESW System and its ability to take water from Lake Erie is described in USAR Section 2.4.11 (Ref. 8).

The Division 1 and 2 ESW subsystems supply cooling water to equipment required for a safe reactor shutdown. Additional information on the design and operation of the ESW System along with the specific equipment for which the ESW System supplies cooling water is provided in the USAR, Section 9.2.1 and the USAR, Table 9.2-7 (Refs. 2 and 3, respectively). The ESW System is designed to withstand a single active or passive failure, coincident with a loss of offsite power, without losing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

(continued)

BASES

BACKGROUND (continued)	Following a DBA or transient, the ESW System will operate automatically without operator action. Manual initiation of supported systems (e.g., suppression pool cooling) is, however, performed for long term cooling operations.
APPLICABLE SAFETY ANALYSES	The volume of Lake Erie is such that sufficient water inventory is available for all ESW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the ESW System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the USAR, Sections 9.2.1, 6.2.1.1.3.3, and Chapter 15, (Refs. 2, 4, and 5, respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA. The ESW System provides cooling water for the RHR suppression pool cooling mode to limit suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its intended function of limiting the release of radioactive materials to the environment following a LOCA. The ESW System also provides cooling to other components assumed to function during a LOCA (e.g., RHR and Low Pressure Core Spray Systems via the Emergency Closed Cooling Water System). Also, the ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the DGs. The safety analyses for long term containment cooling were performed, as discussed in the USAR, Sections 6.2.1.1.3.3 and 6.2.2 (Refs. 4 and 6, respectively), for a LOCA, concurrent with a loss of offsite power, and minimum available DG power. The worst case single failure affecting the performance of the ESW System is the failure of one of the two standby DGs, which would in turn affect one ESW subsystem. Reference 2 discusses ESW System performance during these conditions. The ESW System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

The OPERABILITY of the Division 1 and 2 ESW subsystems is required to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring both ESW subsystems to be OPERABLE ensures that either subsystem will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure.

An ESW subsystem is considered OPERABLE when:

a. The associated pump is OPERABLE; and

b. The associated piping, valves, instrumentation, and controls required to perform the safety related function are OPERABLE.

The isolation of the ESW System to components or systems may render those components or systems inoperable, but may not affect the OPERABILITY of the ESW System.

During the performance of maintenance, repair, or testing activities on an ESW sluice gate, the safety function of the ESW system must be maintained by ensuring that should a loss of the normal ESW intake occur, the alternate water source (discharge tunnel via a sluice gate) remains OPERABLE. The following two approaches describe how this can be done while taking into account the application of the single failure criterion discussed in Generic Letter (GL) 80-30.

First, the ESW loop in the division associated with the closed and inoperable sluice gate can be declared inoperable and the appropriate LCO Condition and Required Actions entered. Per GL 80-30, it is then not necessary to postulate a single failure of the OPERABLE sluice gate while the plant is operating in this time-limited condition. Should the normal ESW intake fail, the OPERABLE sluice gate would open, aligning the ESW loops to the alternate water source. Operators would then align the three ESW loops to the swale per plant procedures.

(continued)

BASES

LCO (continued)	An alternate method would be to align the 3 ESW loops to the swale and then deactivate at least one of the two ESW sluice gates in the open position. In this way either the operable or inoperable sluice gate may be used to maintain all ESW loops OPERABLE provided the sluice gate remains deactivated in the open position. In this way, should the normal ESW intake be lost, the alternate water source (discharge tunnel via the open sluice gate) would be available. This method may only be utilized when there is assurance that the recirculation of warm water from the normal Service Water (SW) system discharge into the ESW Forebay will not result in the ESW inlet temperature exceeding its maximum design limit. OPERABILITY of the Division 3 ESW subsystem is addressed by LCO 3.7.2, "ESW System-Division 3."
APPLICABILITY	In MODES 1, 2, and 3, the Division 1 and 2 ESW subsystems are required to be OPERABLE to support OPERABILITY of the equipment serviced by these ESW subsystems and required to be OPERABLE in these MODES. In MODES 4 and 5, the requirements of the ESW System are determined by the systems they support.
ACTIONS	<u>A.1</u> If one Division 1 or Division 2 ESW subsystem is inoperable, it must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE Division 1 or Division 2 ESW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ESW subsystem could result in loss of ESW function.

(continued)

BASES

ACTIONS

A.1 (continued)

The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE subsystem and the low probability of a DBA occurring during this period.

The Required Action is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources—Operating," and LCO 3.4.9, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," be entered and the Required Actions taken if the inoperable ESW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

B.1 and B.2

If the Division 1 or Division 2 ESW subsystem cannot be restored to OPERABLE status within the associated Completion Time of Condition A, or both Division 1 and Division 2 ESW subsystems are inoperable, 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 12 hours and in MODE 4 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 3.7.1.1

Verifying the correct alignment for each manual, power operated, and automatic valve in each Division 1 and 2 ESW subsystem flow path provides assurance that the proper flow paths exist for ESW subsystem operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

rather, it involves verification that those valves potentially 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.

Isolation of the ESW subsystem to components or systems does not necessarily affect the OPERABILITY of the associated ESW subsystem. As such, when the ESW subsystem pump, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the associated ESW subsystem needs to be evaluated to determine if it is still OPERABLE.

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

SR 3.7.1.2

This SR verifies that the automatic isolation valves of the Division 1 and Division 2 ESW subsystems will automatically realign to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the ESW pump in each subsystem. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function.

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

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. USAR, Section 9.2.1.
3. USAR, Table 9.2-7.

(continued)

BASES

REFERENCES (continued)	4.	USAR, Section 6.2.1.1.3.3.
	5.	USAR, Chapter 15.
	6.	USAR, Section 6.2.2.
	7.	Deleted
	8.	USAR, Section 2.4.11

B 3.7 PLANT SYSTEMS

B 3.7.2 Emergency Service Water (ESW) System-Division

BASES

BACKGROUND	The Division 3 subsystem of the ESW System is designed to provide cooling water for the removal of heat from components of the Division 3 HPCS System. The Division 3 ESW subsystem takes suction from Lake Erie and consists of one cooling water header and the associated pump, piping, valves, and instrumentation. Cooling water is pumped from Lake Erie by the Division 3 ESW pump to the essential components through the Division 3 ESW supply header. After removing heat from the components, the water is discharged to Lake Erie. The Division 3 ESW subsystem supplies cooling water to the Division 3 HPCS diesel generator jacket water coolers and HPCS pump room cooler. The Division 3 ESW pump is sized such that it will provide adequate cooling water to the equipment required for safe shutdown. Following a Design Basis Accident or transient, the Division 3 ESW subsystem will operate automatically and without operator action as described in the USAR, Section 9.2.1 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The ability of the Division 3 ESW subsystem to provide adequate cooling to the HPCS System is an implicit assumption for safety analyses evaluated in the USAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). The Division 3 ESW subsystem satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The Division 3 ESW subsystem is required to be OPERABLE to ensure that the HPCS System will operate as required. An OPERABLE Division 3 ESW subsystem consists of an OPERABLE pump; and an OPERABLE flow path, capable of taking suction from Lake Erie and transferring the water to the appropriate unit equipment.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the Division 3 ESW subsystem is required to be OPERABLE to support OPERABILITY of the HPCS System since it is required to be OPERABLE in these MODES.

In MODES 4 and 5, the requirements of the Division 3 ESW subsystem are determined by the HPCS System.

ACTIONS

A.1

When the Division 3 ESW subsystem is inoperable, the capability of the HPCS System to perform its intended function cannot be ensured. Therefore, if the Division 3 ESW subsystem is inoperable, the HPCS System must be declared inoperable immediately and the applicable Condition(s) of LCO 3.5.1, "ECCS—Operating" entered.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

Verifying the correct alignment for each manual, power operated, and automatic valve in the Division 3 ESW subsystem flow path provides assurance that the proper flow paths will exist for Division 3 ESW subsystem operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is also allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially 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.

Isolation of the Division 3 ESW subsystem to components or systems does not necessarily affect the OPERABILITY of the Division 3 ESW subsystem. As such, when the Division 3 ESW pump, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the Division 3 ESW subsystem needs to be evaluated to determine if it is still OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1 (continued)

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

SR 3.7.2.2

This SR verifies that the automatic isolation valve of the Division 3 ESW subsystem will automatically realign to the safety or emergency position to provide cooling water exclusively to the safety related equipment during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the Division 3 ESW pump. The SR excludes automatic valves that are locked, sealed, or otherwise secured in the actuated position. The SR does not apply to valves that are locked, sealed, or otherwise secured in the actuated position since the affected valves were verified to be in the actuated position prior to being locked, sealed, or otherwise secured. Placing an automatic valve 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 to be repositioned to the non-actuated position to support the accident analysis. Restoration of an automatic valve to the non-actuated position requires verification that the SR has been met within its required Frequency. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this SR to provide complete testing of the safety function.

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

REFERENCES

1. USAR, Section 9.2.1.

2. USAR, Chapter 6.

3. USAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.3 Control Room Emergency Recirculation (CRER) System

BASES

BACKGROUND

The CRER System provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The safety related function of the CRER System used to control radiation exposure consists of two independent and redundant high efficiency air filtration subsystems for treatment of recirculated air and a control room envelope (CRE) boundary that limits the inleakage of unfiltered air. Each CRER subsystem consists of a demister, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork, dampers, and instrumentation. The demister is provided to remove entrained water in the air. The prefilter removes large particulate matter, while the upstream HEPA filter is provided to remove fine particulate matter (which may be radioactive) and protect the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the HEPA after filter is provided to collect any carbon fines exhausted from the charcoal adsorber. When emergency recirculation is activated, the supply fan in the associated control room HVAC subsystem also operates, and its normal flow rate is reduced to be compatible with the CRER fan discussed above (Ref. 2).

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 for normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceilings, 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.

(continued)

BASES

BACKGROUND (continued)

In addition to the safety related standby emergency filtration function, parts of the CRER System are operated to maintain the CRE environment during normal operation. Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to CRE occupants), the CRER System automatically switches to the emergency recirculation mode of operation to minimize infiltration of contaminated air into the CRE. A system of dampers isolates the CRE, and CRE air flow is recirculated and processed through either or both of the two filter subsystems.

The CRER System is designed to maintain a habitable environment in the CRE for a 30 day continuous occupancy after a DBA, without exceeding 5 rem total effective dose equivalent (TEDE). CRER System operation in maintaining the CRE habitability is discussed in the USAR, Sections 6.5.1 and 6.4 (Refs. 1 and 2, respectively).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ability of the CRER System to maintain the habitability of the CRE is an explicit assumption for the safety analyses presented in the USAR, Chapters 6 and 15 (Refs. 3 and 4, respectively). The emergency recirculation mode of the CRER System is assumed to operate following a DBA. The radiological doses to CRE occupants as a result of the various DBAs are summarized in Reference 4. No single active or passive failure will cause the loss of ability to recirculate air in the CRE.

The CRER can provide protection from smoke and hazardous chemicals to CRE occupants. However, an evaluation of chemical hazards from onsite, offsite, and transportation sources has determined that the probability of a hazardous chemical spill resulting in unacceptable exposures is less than NRC licensing basis criteria. As a result, the plant licensing basis does not postulate hazardous chemical release events (Refs. 2 and 5). Therefore, no quantitative limits on inleakage of hazardous chemicals into the CRE have been established. A smoke assessment consistent with the guidance in Regulatory Guide 1.196 (Ref. 7) and NEI 99-03 Rev. 0 (Ref. 10) determined that reactor control capability can be maintained from either the Control Room or the remote shutdown controls during a smoke event (Ref. 6). Therefore, no quantitative limits on inleakage of smoke into the CRE have been established. Because inleakage limits for hazardous chemicals and smoke are not necessary to protect CRE occupants, the limit established for radiological events is the limiting value for CRE inleakage.

The CRER System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, or 3. During MODES 4 and 5, there are no accident analyses that credit the CRER System. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the CRER System during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

LCO

Two redundant subsystems of the CRER System are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other subsystem. Total system failure, such as from a loss of both ventilation subsystems or from an inoperable CRE

(continued)

BASES

LCO (continued)

boundary, could result in a failure to meet the dose requirements of GDC 19 in the event of a DBA.

Each CRER subsystem is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CRER subsystem is considered OPERABLE when its associated:

a. Fans are 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.

In order for the CRER subsystems 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 such openings (other than doors), 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. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area.

APPLICABILITY

In MODES 1, 2, and 3, the CRER System must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA, since the DBA could lead to a fission product release.

(continued)

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CRER System OPERABLE is not required in MODE 4 or 5, except during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building.

Due to radioactive decay, handling of fuel only requires OPERABILITY of the Control Room Emergency Recirculation System when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during “movement of recently irradiated fuel”, which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 4).

ACTIONS

A.1

With one CRER subsystem inoperable for reasons other than an inoperable CRE boundary, the inoperable CRER subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE CRER subsystem is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CRER subsystem could result in loss of CRER System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 Rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. As discussed in the Applicable Safety Analyses section, the current PNPP licensing basis identifies that CRE inleakage limits for hazardous chemicals and smoke are not necessary to protect CRE occupants; therefore the limit established for radiological events is the limiting value for determining entry into Condition B for an inoperable CRE boundary. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. These mitigating actions are outlined in the PNPP Control Room Envelope Habitability Program.

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.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable CRER subsystem or the CRE boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 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.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

The Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown. During movement of recently irradiated fuel assemblies in the primary containment or fuel handling building, if the inoperable CRER subsystem cannot be restored to OPERABLE status within the required Completion Time of Condition A, the OPERABLE CRER subsystem may be placed in the emergency recirculation mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing significant amounts of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk.

If applicable, movement of recently irradiated fuel assemblies in the primary containment and fuel handling building must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

E.1

If both CRER subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CRE boundary (i.e., Condition B), the CRER System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

ACTIONS (continued)

F.1

During movement of recently irradiated fuel assemblies in the primary containment or fuel handling building, with two CRER subsystems inoperable or with one or more CRER subsystems inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that present a potential for releasing significant amounts of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk.

If applicable, movement of recently irradiated fuel assemblies in the primary containment and fuel handling building must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

Operating each CRER subsystem for ≥ 15 continuous minutes after initiating from the control room and ensuring flow through the HEPA filters and charcoal adsorbers ensures that both subsystems are OPERABLE and that all associated controls are functioning properly (Ref. 12). It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.3.2

This SR verifies that the required CRER testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter efficiency, charcoal adsorber efficiency and bypass leakage, system flow rate, and general operating parameters of the filtration system. (Note: Values identified in the VFTP are Surveillance Requirement values.). Specific test Frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.3

This SR verifies that each CRER subsystem starts and operates on an actual or simulated initiation signal, and the isolation dampers that establish a portion of the CRE boundary close within 10 seconds. 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 LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.5 overlaps this SR to provide complete testing of the safety function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.3.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3, (Ref. 7), which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 10). These compensatory measures may be used as mitigating actions as required by Required Action B.2.

Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.3.4 (continued)

CRE boundary, or a combination of these actions (Ref. 11). 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.

REFERENCES

1. USAR, Section 6.5.1.
2. USAR, Section 6.4.
3. USAR, Chapter 6.
4. USAR, Chapter 15.
5. USAR, Section 2.2.
6. Letter from L. W. Pearce (FENOC) to Document Control Desk (NRC) dated May 30, 2006, “Perry Nuclear Power Plant Final Response to Generic Letter 2003-01, ‘Control Room Habitability’ (TAC No. MB9839).”
7. Regulatory Guide 1.196.
8. Deleted.
9. Deleted.
10. NEI 99-03, "Control Room Habitability Assessment," June 2001.
11. 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. ML040160868).
12. Regulatory Guide 1.52, Revision 4.

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Heating, Ventilating, and Air Conditioning (HVAC) System

BASES

BACKGROUND

The Control Room HVAC System provides temperature control for the control room following isolation of the control room.

The Control Room HVAC System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room air. Each subsystem consists of heating coils, cooling coils, fans, chillers with compressors, ductwork, dampers, and instrumentation and controls to provide for control room temperature control.

The Control Room HVAC System is designed to provide a controlled environment under both normal and accident conditions. The Control Room HVAC System operation in maintaining the control room temperature is discussed in the USAR, Sections 6.4 and 9.4.1 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the Control Room HVAC System is to maintain the control room temperature for a 30 day continuous occupancy.

The Control Room HVAC System components are arranged in redundant safety related subsystems. During emergency operation, the Control Room HVAC System maintains a habitable environment and ensures the OPERABILITY of components in the control room. A single active failure of a component of the Control Room HVAC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The Control Room HVAC System is designed in accordance with Seismic Category I requirements. The Control Room HVAC System is capable of removing sensible and latent heat loads from the control room, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Control Room HVAC System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) in MODES 1, 2, and 3. During MODES 4 and 5, there are no accident analyses that credit the Control Room HVAC System. However, it was determined that Specifications should remain in place per Criterion 4 to address fuel handling accidents. Criterion 3 would apply if dose calculations are revised to credit the Control Room HVAC during handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

(continued)

BASES (continued)

LCO

Two independent and redundant subsystems of the Control Room HVAC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other subsystem. Total system failure could result in the equipment operating temperature exceeding limits.

The Control Room HVAC System is considered OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, chillers with compressors, ductwork, dampers, and associated instrumentation and controls. The heating coils are not required for control room HVAC OPERABILITY.

APPLICABILITY

In MODE 1, 2, or 3, the Control Room HVAC System must be OPERABLE to ensure that the control room temperature will not exceed equipment OPERABILITY limits.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room HVAC System OPERABLE is not required in MODE 4 or 5, except during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building.

Due to radioactive decay, handling of fuel only requires OPERABILITY of the Control Room HVAC System when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. Although this Function retains APPLICABILITY during "movement of recently irradiated fuel", which could be interpreted to permit fuel handling before 24 hours of radiological decay if certain buildings and filtration systems are OPERABLE, this is not the case. Fuel handling during that period is prohibited since no dose calculations exist to address a fuel handling accident within the first 24 hours after the reactor core is sub-critical (Ref. 3).

(continued)

BASES (continued)

ACTIONS

A.1

With one control room HVAC subsystem inoperable, the inoperable control room HVAC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE control room HVAC subsystem is adequate to perform the control room air

(continued)

ACTIONS

A.1 (continued)

conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in loss of the control room air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring control room isolation, the consideration that the remaining subsystem can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

If both control room HVAC subsystems are inoperable, the Control Room HVAC System may not be capable of performing its intended function. Therefore, the control room air temperature is required to be monitored to ensure that temperature is maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 7 days is allowed to restore a control room HVAC subsystem to OPERABLE status. This Completion Time is reasonable considering that the control room temperature is being maintained within limits, the low probability of an event occurring requiring control room isolation, and the availability of alternate cooling methods.

C.1 and C.2

In MODE 1, 2, or 3, if the control room area temperature cannot be maintained ≤ 90 °F or if the inoperable control room HVAC subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 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.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

The Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the primary containment or fuel handling building, if the inoperable control room HVAC subsystem cannot be restored to OPERABLE status within the required Completion Time of Condition A, the OPERABLE control room HVAC subsystem may be placed immediately in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that present a potential for releasing significant amounts of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, movement of recently irradiated fuel assemblies in the primary containment and fuel handling building must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

(continued)

BASES

ACTIONS (continued)

E.1

The Required Actions of Condition E.1 are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the primary containment or fuel handling building, if the Required Action and associated Completion Time of Condition B is not met, action must be taken to immediately suspend activities that present a potential for releasing significant amounts of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, handling of recently irradiated fuel in the primary containment or fuel handling building must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that the heat removal capability of the system is sufficient to remove the control room heat load assumed in the safety analysis. The SR consists of a combination of testing and calculation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. USAR, Section 6.4.

2. USAR, Section 9.4.1.

3. USAR, Section 15.7.6.

B 3.7 PLANT SYSTEMS

B 3.7.5 Main Condenser Offgas

BASES

BACKGROUND	During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.
APPLICABLE SAFETY ANALYSES	The main condenser offgas release rate is an initial condition of the Main Condenser Offgas System failure event as discussed in the USAR, Section 15.7.1 (Ref. 1). The analysis assumes a gross failure in the Main Condenser Offgas System that results in the rupture of the Main Condenser Offgas System pressure boundary. The release rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits of 10 CFR 50.67 (Ref. 3), or the NRC staff approved licensing basis. The main condenser offgas limits satisfy Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132). The Offgas limit specified in TS 3.7.5 represents a short term conservative limit for accident analysis purposes. The operational limits defined by TS sections 5.5.1 and 5.5.4 and by the ODCM ensure that the annual average Offgas release rates are significantly under this, and ensure consistency with the design bases for annual average release limits and shielding analyses.
LCO	To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission

(continued)

BASES

LCO (continued)

product release rate should be consistent with a noble gas release to the reactor coolant of 100 μCi/MWt-second after decay of 30 minutes. The LCO is conservatively established at (3579 MWT x 100 μCi/MWt-second = 358 mCi/second).

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the release rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment considering the time required to complete the Required Action, the large margins associated with permissible dose and exposure limits, and the low probability of a Main Condenser Offgas System rupture occurring.

B.1, B.2, B.3.1, and B.3.2

If the release rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit 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 12 hours and in MODE 4 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR requires an isotopic analysis within 4 hours of noting a significant increase as indicated by the Offgas Pretreatment Radiation Monitor in the measured release rate of radioactivity. The analysis is performed on a representative sample of gases taken at the discharge (i.e. prior to dilution or discharge) of the steam jet air ejector. A significant increase is defined as an increase in release rate greater than or equal to 50% after correcting for expected increases due to changes in THERMAL POWER. This SR is to ensure that the increase is not indicative of a sustained increase in the radioactive release rate.

SR 3.7.5.2

This SR requires a periodic isotopic analysis of a representative off gas sample to ensure that the required limits are satisfied. The analysis is performed on a representative sample of gases taken at the discharge (i.e. prior to dilution or discharge) of the steam jet air ejector. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. USAR, Section 15.7.1.
2. NUREG-0800.
3. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 28.8% (nominal) of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of two valve chests connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Steam Bypass and Pressure Regulating System, as discussed in the USAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed control unit or the load control unit restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.
APPLICABLE SAFETY ANALYSES	The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in the USAR, Section 15.1.2 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. The Main Turbine Bypass System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded.

An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 23.8% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists < 23.8% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status within the associated Completion Time, THERMAL POWER must be reduced to < 23.8% RTP. As discussed in the Applicability section, operation at < 23.8% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable,

(continued)

ACTIONS

B.1 (continued)

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

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.6.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.6.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The TURBINE BYPASS SYSTEM RESPONSE TIME must comply with the following requirements when measured from the initial movement of the main turbine stop or control valve:

a. 80% of turbine bypass system capacity shall be established in less than or equal to 0.3 seconds.

b. Bypass valve opening shall start in less than or equal to 0.1 seconds.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.6.3 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 7.7.1.5. 2. USAR, Section 15.1.2.

B 3.7 PLANT SYSTEMS

B 3.7.7 Fuel Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel storage pools and upper containment fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident. A general description of the fuel handling building (FHB) spent fuel storage pools and upper containment fuel storage pool design is found in the USAR, Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in the USAR, Sections 15.7.4 and 15.7.6 (Refs. 2 and 3, respectively).
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the offsite radiological consequences (calculated Total Effective Dose Equivalent (TEDE) doses at the exclusion area and low population zone boundaries) are ≤ 25% of the 10 CFR 50.67 (Ref. 5) exposure guidelines. The Control Room is also evaluated to ensure doses are less than the 10 CFR 50.67 exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.183 (Ref. 6). The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto stored fuel bundles. The consequences of a fuel handling accident inside the FHB and inside containment are documented in References 2 and 3, respectively. The water levels in the FHB spent fuel storage pools and upper containment fuel storage pools provide for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident. The fuel pool water level satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO	The specified water level preserves the assumption of the fuel handling accident analysis (Refs. 2 and 3). As such, it is the minimum required for fuel movement within the FHB spent fuel storage pools and upper containment fuel storage pool.
APPLICABILITY	This LCO applies whenever movement of irradiated fuel assemblies occurs in the associated fuel storage racks since the potential for a release of fission products exists.
ACTIONS	A.1 Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown. When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With either fuel storage pool level less than required, the movement of irradiated fuel assemblies in the associated fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.
SURVEILLANCE REQUIREMENTS	SR 3.7.7.1 This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the FHB spent fuel storage pools and upper containment fuel storage pool must be checked periodically. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. USAR, Section 9.1.2.
2. USAR, Section 15.7.4.
3. USAR, Section 15.7.6.
4. Deleted
5. 10 CFR 50.67.
6. Regulatory Guide 1.183, July 2000.

B 3.7 PLANT SYSTEMS

B 3.7.10 Emergency Closed Cooling Water (ECCW) System

BASES

BACKGROUND

The ECCW 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 ECCW System is maintained in a standby condition. The ECCW system is also required to operate when the plant is in a hot standby condition, and during a normal shutdown period to supply cooling water to the RHR pump seals and room coolers. The ECCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Emergency Service Water System, and thus to the environment.

The ECCW System consists of two independent and redundant subsystems that provide cooling water to safety related equipment. Each ECCW subsystem consists of a pump, surge tank, heat exchanger, piping, valves, instrumentation, and controls. An open surge tank in the system provides alarm functions to ensure sufficient net positive suction head is available. The pump in each subsystem is automatically started on receipt of an actuation signal.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the USAR, Section 9.2.2, (Ref. 1). The principal safety related function of the ECCW System is to supply cooling water to RHR, LPCS, and RCIC room coolers, RHR pump seals, and cooling water to the hydrogen analyzers. The ECCW system also supplies the emergency source of cooling water to the control complex chillers.

APPLICABLE SAFETY ANALYSIS

The design basis of the ECCW System is to support the Emergency Core Cooling System and other safety related equipment following an accident.

The ECCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The ECCW System satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	In the event of a DBA, one ECCW subsystem 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 ECCW subsystems must be OPERABLE. At least one ECCW subsystem will operate assuming the worst single active failure occurs coincident with the loss of offsite power. An ECCW subsystem is considered OPERABLE when: a. The associated pump and 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 ECCW to other components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ECCW System. Several valves that were originally designed as part of Unit 2's ECCW system have retained ECCW (P42) identification numbers, even though the valves have no relationship with the Unit 1 ECCW system addressed by this LCO. Several of these valves are closed in order to isolate Nuclear Closed Cooling (NCC) from the Unit 1 Emergency Service Water (ESW) system when ESW is to be aligned to cool the Spent Fuel Pool heat exchangers. Other valves are opened to provide the ESW flow path to the heat exchangers. Those Unit 2/Common valves do not affect OPERABILITY of Unit 1 ECCW; they are instead associated with OPERABILITY of the Unit 1 ESW system.
APPLICABILITY	In MODE 1, the ECCW subsystems are in standby except when required to support RHR, LPCS, or RCIC System operations and testing. In MODES 2 and 3, the ECCW System is operated as necessary to support hot standby conditions or normal plant shutdown and cooldown using the RHR System. In MODES 4 and 5, the requirements of the ECCW System are determined by the systems they support (Ref. 2).

(continued)

BASES (continued)

ACTIONS

A.1

With one or both ECCW subsystems inoperable, all the associated subsystem(s) or component(s) must immediately be declared inoperable.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A are not met, 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 12 hours and in MODE 4 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 3.7.10.1

Verifying the correct alignment for each manual, power operated, and automatic valve in the ECCW subsystem flow path provides assurance that the proper flow paths exist for ECCW subsystem operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a non-accident position provided the valve will automatically reposition in the proper stroke time. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves potentially capable of being mispositioned are in the correct position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1 (continued)

Isolation of the ECCW subsystem to components or systems does not necessarily affect the OPERABILITY of the ECCW subsystem. As such, when the ECCW subsystem pump, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the associated ECCW subsystem needs to be evaluated to determine if it is still OPERABLE.

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

SR 3.7.10.2

This SR verifies that each Unit 1 Division 1 and 2 ECCW subsystem actuates on an actual or simulated initiation signal, including verification of the automatic start capability of the ECCW pump in each subsystem. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.6 overlaps this Surveillance to provide complete testing of the safety function.

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

REFERENCES

1. USAR, Section 9.2.2.
2. Plant Data Book, Tab R, Section 6.4.9.

B 3.7 PLANT SYSTEMS

B 3.7.11 Flood Protection

BASES

BACKGROUND

As originally licensed, the design of the Perry Nuclear Power Plant (PNPP) facility for flood protection conformed to the requirements of 10 CFR 50, Appendix A, GDC 2 (Ref. 1) with respect to protection against natural phenomena. The design of the facility met the acceptance criteria of Section 3.4.1 of NUREG-0800 (Ref. 2). The flood hazard protection scheme was entirely passive.

Throughout the life of the facility, various changes to the immediate plant area have occurred that have affected the runoff characteristics of overland flow of water and resulted in less effective drainage characteristics. The cumulative change in overland water discharge paths has resulted in inefficient site drainage for the local intense precipitation (LIP) flooding event and the potential for floodwater intrusion into safety-related buildings and non-safety related buildings that potentially communicate with safety-related buildings. This change, combined with a reconstituted hydrologic analysis, resulted in a change to the flood hazard protection scheme for PNPP to one that is now partially passive.

Flood barriers used at PNPP include passive (permanent or normally installed/deployed) barriers and temporary incorporated barriers as defined in Regulatory Guide 1.102 (Ref. 3). The flood barriers are not active components.

As described in the PNPP Updated Safety Analysis Report (USAR) Section 2.4.10 (Ref. 4), PNPP is passively protected from external flooding hazards from the adjacent streams (referred to as the Major Stream and the Diversion Stream) and Lake Erie for the entire range of postulated flooding events. The LIP flooding event represents the bounding external flood hazard for PNPP. The PNPP LIP domain consists of the site property bounded on the north by Lake Erie, the east by the new Diversion Stream, the west by the Major Stream, and to the south by the Major and Diversion Streams' drainage basins. The LIP domain is passively protected for flooding events up to and including the Standard Project Storm (SPS) determined by engineering calculation 50:75.000 (Ref. 5). Precipitation (rainfall) events in excess of the SPS require deployment of temporary flood protection barriers in order to preserve the function of safety-related structures, systems, and components (SSCs).

(continued)

BASES

BACKGROUND (continued)

Hydraulic analyses have determined the point at which the permanent and passive protection features (such as walls, door sills/closure plates/ramps, dike, berms, administratively closed openings, etc.) would be exceeded due to precipitation events. The precipitation event at which passive protection is exceeded is used to define the site's consequential rainfall event. These values are used to establish two meteorological (weather) forecast warning levels, Monitoring Threshold and Trigger Event. The two meteorological warning levels used for PNPP are determined by engineering calculation 50:85.000 (Ref. 6).

The Monitoring Threshold warning level is set at 2.1 inches of rainfall in a 24-hour period. This warning level serves as an initial warning of possible forthcoming significant precipitation at the site. This event corresponds to a 1-year recurrence interval precipitation event.

The Trigger Event warning level is set at a precipitation intensity of 1.9 inches in 1 hour (Ref. 5). The Trigger Event is not an actual precipitation event, rather, it is a control setpoint intended to initiate operator actions to deploy mitigation strategies for a possible forthcoming consequential rainfall event. This event corresponds to an approximately 18-year recurrence interval precipitation event. Setpoints are also provided for 6-, 12-, and 24-hour event durations of the same recurrence interval.

For PNPP, meteorological forecast monitoring ensures the site is alerted in advance of a consequential rainfall event so that flood mitigation can be implemented to maintain plant safety. Meteorological forecast monitoring is provided via an external meteorological service, as described in Reference 4. The meteorological forecasting employs an ensemble technique using diversified inputs and a 95th percentile confidence value. This meteorological forecast monitoring provides an allowance of 12 hours for deployment of flood barriers, which is sufficient time for operators to deploy the barriers prior to the need for initiation of plant shutdown.

Flood barrier deployment is implemented via site procedure ONI-ZZZ-1 (Ref. 7). Barrier size and locations have been determined in order to prevent floodwater intrusion into safety-related buildings and non-safety related buildings that potentially communicate with safety-related buildings.

This Technical Specification ensures temporary flood protection barriers are deployed in advance of a LIP flooding event.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The flood design basis for the PNPP site includes use of deployable flood barriers to protect site safety-related buildings and non-safety related buildings that potentially communicate with safety-related buildings in the LIP flood hazard event. The deployment of these flood protection features preserves the function of safety-related SSCs. The flood protection scheme precludes the plant from entering an unanalyzed condition, serves as the assumed initial condition for the design basis LIP flood event, and imposes an operating restriction on the plant. The flood protection scheme also serves as the primary success path to mitigate the design basis LIP flood. The flood protection scheme satisfies Criterion 2 and Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	The flood hazard analysis determined that LIP flooding is the bounding external flood hazard for PNPP. Deployment of flood barriers is required to prevent floodwater intrusion into safety-related buildings and non-safety related buildings that potentially communicate with safety-related buildings, thus protecting safety-related SSCs. The Trigger Event warning level is set such that actions can be taken to mitigate flooding from a possible forthcoming consequential rainfall event.
APPLICABILITY	Flood protection is required at all times to protect safety-related SSCs relied upon for safe operation, normal plant shutdown, to maintain cold shutdown conditions, and to maintain shutdown and refueling conditions because the Trigger Event could occur at any time.
ACTIONS	<u>A.1</u> With the requirements of the LCO not met, deployment of flood barriers must occur to protect the plant from floodwater intrusion into safety-related buildings and non-safety related buildings that potentially communicate with safety-related buildings. Sufficient time is allowed so that the flood barriers are in place 36 hours prior to the projected start of the Trigger Event itself. The allowed Completion Time is reasonable.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With the Required Action and Completion Time of A.1 not met in MODE 1, 2, or 3, the plant must be brought to MODE 3 within 12 hours and MODE 4 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.

C.1, C.2, C.3, C.4, and C.5

All CORE ALTERATIONS except control rod insertion, if in progress, are immediately suspended in accordance with Required Action C.1, and action to fully insert all insertable control rods in core cells containing one or more fuel assemblies is initiated immediately in accordance with Required Action C.2. Action initiated under Required Action C.2 must continue until all insertable control rods containing one or more fuel assemblies have been fully inserted. This will preclude mechanisms that could lead to criticality. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Control rods in core cells containing no fuel assemblies do not affect reactivity of the core and therefore do not have to be inserted.

Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes restoring primary containment to OPERABLE status, and primary containment isolation capability (i.e., one closed door in each primary containment air lock, and at least one primary containment isolation valve associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, Surveillances may need to be performed to restore the component to OPERABLE status. In

(continued)

BASES

ACTIONS (continued)

addition, at least one door in each primary containment air lock must be closed. The closed air lock door completes the boundary for control of potential radioactive releases. With the appropriate administrative controls however, the closed door can be opened intermittently for entry and exit. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the door except during the entry and exit, and assuring the door is closed after completion of the containment entry and exit. This allowance is acceptable due to the need for containment access and due to the slow progression of events that may result from inadequate shutdown margin. Inadvertent reactor criticalities would not be expected to result in the immediate release of appreciable fission products to the containment atmosphere. Actions must continue until all requirements of this Condition are satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

A 7-day meteorological forecast is used to monitor for a Trigger Event and provides ample warning time for deployment of flood protection barriers. If barriers are not deployed in the timeframe allotted, there is sufficient warning time available for a plant shutdown to occur.

An external meteorological service is employed to continuously monitor meteorological conditions at the site and issue automated alerts to control room personnel to support this surveillance requirement.

Monitoring the meteorological forecasting every 24 hours, provides plant personnel with the opportunity to ensure the site is in a flood-ready condition prior to the arrival of a consequential rain event.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 2.
2. NUREG-0800, “Standard Review Plan,” Section 3.4.1.
3. Regulatory Guide 1.102.
4. USAR, Section 2.4.10.
5. Calculation 50:75.000, Design Basis Standard Project Storm (SPS) Determination
6. Calculation 50:85.000, Precipitation Hazard Alert Evaluation.
7. ONI-ZZZ-1, Acts of Nature – Severe Weather.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources-Operating

BASES

BACKGROUND

The plant Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources and the onsite standby power sources (Division 1, 2, and 3 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 Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus (refer to LCO 3.8.7, "Distribution Systems-Operating"). Each ESF bus receives power from the 345 kV grid through two separate independent circuits. Each ESF bus has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the transmission network. From the switchyard two electrically and physically separated circuits provide AC power to each 4.16 kV ESF bus. The offsite AC electrical power circuits are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and circuits to the onsite Class 1E ESF buses is found in USAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls

(continued)

BASES

BACKGROUND (continued)

required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation").

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 LOCA.

Certain required plant 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 or to prevent overloading the DG.

Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating is 7000 Kw for Divisions 1 and 2 and is 2600 Kw for Division 3, with 10% overload permissible for up to 2 hours in any 24 hour period.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the USAR, 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 as discussed in Reference 2. This includes maintaining 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	b. A worst case single failure. AC sources satisfy the requirements of Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent DGs (Divisions 1, 2, and 3), ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the USAR and are part of the licensing basis for the unit.

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. One offsite circuit consists of the Unit 1 startup transformer through the Unit 1 interbus transformer, to the Class 1E 4.16 kV ESF buses through source feeder breakers for each division. The second offsite circuit consists of the Unit 2 startup transformer through the Unit 2 interbus transformer, to the Class 1E 4.16 kV ESF buses through source feeder breakers for each division. There are at least two separate paths, with sufficient capacity provided from the transmission network to the standby power distribution system, in accordance with GDC-17, to respond to anticipated operational occurrences. The circuits are designed to be available within a few seconds following a loss-of-coolant accident.

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 sequence must be accomplished within 10 seconds for the Division 1 and 2 DGs;

(continued)

BASES

LCO (continued)

and 13 seconds for the Division 3 DG. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must 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 engine hot and DG in standby with 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 both offsite circuit and DG OPERABILITY for Divisions 1 and 2.

The AC sources in one division must be separate and independent (to the extent possible) of the AC sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 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.

A Note has been added taking exception to the Applicability requirements for Division 3 AC sources, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the HPCS System inoperable either in lieu of declaring the Division 3 AC source inoperable, or at any time subsequent to entering ACTIONS for an inoperable Division 3 AC source. This exception is acceptable since, with the HPCS System inoperable and the associated ACTIONS entered, the Division 3 AC sources provide no additional assurance of meeting the above criteria.

AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources-Shutdown."

(continued)

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG, and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required 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 the Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A 2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. This Completion Time assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. In the event one or more divisions are without offsite power, this assumption is not met, therefore the optional 24 hour Completion Time is specified. Should two (or more) divisions be affected, the 24 hour Completion Time is conservative with respect to the Regulatory Guide assumptions supporting a 24 hour Completion Time for both offsite circuits inoperable. With one 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 plant 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 Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The last Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 17 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 day Completion Times for Required Action

(continued)

BASES

ACTIONS

A.2 (continued)

A.2 means that both Completion Times apply simultaneously, and the more restrictive must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

B.1

To ensure a highly reliable power source remains, it is necessary to verify the availability 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 being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions 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 loss of safety function of critical features (systems, subsystems, components, or devices). These features are designed with redundant safety related divisions (i.e., single division features are excluded, although, for this Required Action, Division 3 must be included, and must be considered redundant to Division 1 and 2 Emergency Core Cooling System (ECCS)). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG. When performing the ECCS portion of this cross-division check, if any ECCS system(s)/subsystem(s) in either of the other two redundant divisions are discovered to be inoperable, the Completion Time begins; when it expires, all ECCS supported by the inoperable DG are declared inoperable.

The Completion Time 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

(continued)

BASES

ACTIONS

B.2 (continued)

b. A required feature on another division is inoperable.

If, at any time during the existence of this Condition (one DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more required support or supported features, or both, that are associated with the OPERABLE DG(s), results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs 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 component 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, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) are declared inoperable upon discovery, and Condition E and potentially Condition G of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, 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(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

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BASES

ACTIONS

B.3.1 and B.3.2 (continued)

In the event the inoperable DG is restored to OPERABLE status prior to completing either Required Actions B.3.1 or B.3.2, the corrective actions program will continue to evaluate the common cause failure 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 time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time for Division 3 and the 14 day Completion Time for Divisions 1 and 2 take into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The Division 1 and 2 Emergency Diesel Generators (EDGs) have a 14 day Completion Time. The period of the Completion Time that is ≥ 72 hours is considered to be the "risk-informed" portion of the Completion Time. The provisions of the Configuration Risk Management Program (CRMP)in Specification 5.5.13.1 must be applied to use the risk-informed portion of the Completion Time. The risk-informed portion of the Completion Time is meant to be entered in a controlled fashion whenever possible with a work scope that limits the risk to the plant. The CRMP is controlled by plant administrative procedures.

One preventive maintenance outage using the risk-informed portion of the 14 day Completion Time may be planned for one EDG, Division 1 or 2, within a period of 365 days (one year). The basis of the "once per year" frequency is to minimize the number of times that major intrusive maintenance is performed on the diesels. In accordance with the CRMP and the acceptance criteria of RG 1.177, a qualitative assessment may be used to assess time periods between planned extended preventive maintenance outages of less than one year.

(continued)

BASES

ACTIONS

B.4 (continued)

The risk-informed provisions in the CRMP also apply if entry into the risk-informed portion of the Completion Time is necessary for corrective maintenance. In addition, the 10CFR50.65 (Maintenance Rule) program includes performance criteria for cumulative out-of-service time of the diesels. Entries into the risk-informed portion of the Completion Time for corrective maintenance do not affect the "once per year" frequency of planned extended outages described above, although such entries may shorten the allowable length of a planned preventive maintenance outage due to the Maintenance Rule performance criteria.

The third Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "<u>AND</u>" connector between the Completion Times means that the three Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

ACTIONS

B.4 (continued)

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features (systems, subsystems, components, or devices). Required Action C.1 reduces the vulnerability to a loss of function. The rationale for the 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 divisions 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. These features are designed with redundant safety related divisions (i.e., single division systems are excluded, although, for this Required Action, Division 3 must be included, and must be considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

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 this Condition (two offsite circuits inoperable), a required feature subsequently 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. 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 degradation level:

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 Regulatory Guide 1.93 (Ref. 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

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Actions for LCO 3.8.7 "Distribution Systems-Operating," 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 any division, Actions for LCO 3.8.7 must be immediately entered. This allows Condition D to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours. 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, reasonable time for repairs, and low probability of a DBA occurring during this period.

E.1

With two DGs inoperable, there is one remaining standby AC source. 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 the majority of ESF equipment at this level of degradation,

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BASES

ACTIONS

E.1 (continued)

the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, 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 Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours. This Completion Time assumes complete loss of onsite (DG) AC capability to power the minimum loads needed to respond to analyzed events. In the event Division 3 DG in conjunction with Division 1 or 2 DG is inoperable, with Division 1 or 2 remaining, a significant spectrum of breaks would be capable of being responded to with onsite power. Even the worst case event would be mitigated to some extent – an extent greater than a typical two division design in which this condition represents complete loss of onsite power function. Given the remaining function, a 24 hour Completion Time is appropriate. At the end of this 24 hour period, the HPCS System could be declared inoperable (see Applicability Note) and this Condition could be exited with only one required DG remaining inoperable. However, with a Division 1 or 2 DG remaining inoperable and the HPCS System declared inoperable, a redundant required feature failure exists, according to Required Action B.2.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 12 hours and to MODE 4 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

ACTIONS (continued)

G.1

Condition G corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

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, 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).

Where the SRs discussed herein specify voltage and frequency tolerances, the minimum and maximum steady state output voltages are 3900 V and 4400 V, respectively. The minimum allowable DG voltage provides an acceptable margin above the maximum allowable degraded voltage relay reset value. The maximum allowable DG voltage is based on the maximum safety bus voltage which will result in a worst case over-excitation level of 111% at the terminals of any device connected to the bus. The specified minimum and maximum frequencies of the DG of 58.8 Hz and 61.2 Hz, respectively, are equal to ± 2% of the 60 Hz nominal frequency. The specified steady state voltage and frequency ranges 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

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 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 have been modified by Notes (Note 2 for SR 3.8.1.2 and Note 1 for SR 3.8.1.7) 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.

For the purposes of this 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 for Division 1 and 2 DGs. For the Division 3 DG, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation.

In order to reduce stress and wear on diesel engines, some manufacturers recommend that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3. This capability is not yet available on the Perry Division 3 DG. The Division 1 and 2 Slow/Fast switches are maintained in 'fast' until slow start switch position and associated circuit is fully tested and functional.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

SR 3.8.1.7 requires that the Division 1 and 2 DGs start from standby conditions and achieve required voltage and frequency within 10 seconds. Also, this SR requires that the Division 3 DG starts from standby conditions and achieves required voltage and frequency within 13 seconds. The start time requirements support the assumptions in the design basis LOCA analysis (Ref. 5). The start time requirements are not applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2). Since SR 3.8.1.7 does require timed starts, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2. Similarly, the performance of SR 3.8.1.12 or SR 3.8.1.19 also satisfies the requirements of SR 3.8.1.2 and SR 3.8.1.7.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

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

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. The load band for the Division 1 and 2 DGs is provided to avoid routine overloading of these DGs. While this Surveillance allows operation of the Division 1 and 2 DGs in the band of 5600 kW to 7000 kW, a range of 5600 kW to 5800 kW will normally be used in order to minimize wear on the DGs. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. 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 1.0 is an operational limitation to ensure circulating currents are minimized.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

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

Note 1 modifies this Surveillance to indicate 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 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance shall 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.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level that will ensure transfer pump operation and availability. This level is expressed as an equivalent volume in gallons, and will ensure fuel oil transfer pump suction requirements are satisfied for all pump operating transients, including normal tank draw down during a secondary pump start.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Subsequent to receipt of a diesel generator auto-initiation alarm, plant operators would be able to verify proper primary and secondary

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

transfer pump operation using the day tank low level alarm during diesel operation. The low level alarm is set above the minimum day tank level requirements needed to support secondary pump operation.

Actuation of this alarm prior to or after auto-initiation of the diesel generator would indicate that primary pump operation has failed and that initiation of the secondary transfer pump should have occurred. Subsequent to secondary pump actuation, plant operators will observe that the low level alarm will be activated during the normal draw down process in the day tank, and that the alarm will reset indicating proper operation of the secondary transfer pump.

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. Periodic removal of water from the fuel oil day tanks eliminates the necessary environment for bacterial survival. This is an 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.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates to automatically transfer fuel oil from its associated storage tank to its associated day tank. Only one transfer pump is required to be OPERABLE for the DG to be OPERABLE. The transfer pump is required to support the continuous operation of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

standby power sources. This Surveillance provides assurance that each 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 design of the fuel transfer systems is such that pumps operate automatically in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by a Note. This Note is not applicable to Division 3. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Maintenance; and

2) Post 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The referenced load for the Division 1 DG is the 1400 kW low pressure core spray pump; for the Division 2 DG, the 729 kW residual heat removal (RHR) pump; and for the Division 3 DG the 2400 kW HPCS pump. This surveillance may be accomplished by: 1) tripping the DG output breaker with the associated single largest load while paralleled to offsite power, or while solely supplying the bus, or 2) tripping its associated single largest load with the DG solely supplying the bus. As required by IEEE-308 (Ref. 13), 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.

This SR has been modified by two Notes. Note 1 is not applicable to Division 3. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. 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 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(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, Note 2 requires that, if synchronized to offsite power, testing be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load, i.e., maximum expected accident 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 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 DG damage protection. While the DG is not expected to experience this transient during an event and continue 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.

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 power factor ≤ .9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

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

This SR has been modified by a Note. This Note is not applicable to Division 3. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

systems that could challenge continued steady state operation and, as a result, plant 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 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.11

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 Division 1 and 2 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 3.8.1.11 (continued)

The DG auto-start times are derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and energization of permanent and auto-connected loads through the load sequence (individual load timers) 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, systems are not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

capable of being operated at full flow, or RHR subsystems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and energization of these 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 being continuously circulated and temperature maintained consistent with manufacturer recommendations for Division 1 and 2 DGs. For the Division 3 DG, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. Note 2 is not applicable to Division 3. 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 plant 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 maintenance testing that requires performance of portions of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

testing, and other unanticipated OPERABILITY concerns). Performance of portions of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds for Divisions 1 and 2 and 13 seconds for Division 3) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

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

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 being continuously circulated and temperature maintained consistent with manufacturer recommendations for Division 1 and 2 DGs. For the Division 3 DG, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. Note 2 is not applicable to Division 3. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. 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 maintenance testing that requires performance of portions of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

testing, and other unanticipated OPERABILITY concerns). Performance of portions of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an ECCS initiation test signal. Non-critical automatic trips are all automatic trips except: a) engine overspeed and b) generator differential current. The non-critical trips are bypassed during DBAs and provide alarms on abnormal engine conditions. These alarms provide the operator with necessary information 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.

This SR is modified by a Note. This Note is not applicable to Division 3. The reason for the Note is that performing the Surveillance removes 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

2) Post 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(3), requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours-22 hours of which is at a load equivalent to the continuous rating of the DG, and 2 hours of which is at a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

load equivalent to 110% of the continuous duty rating of the DG. An exception to the loading requirements is made for Division 1 and 2 DGs since the load carrying capability testing of the Transamerica Delaval Inc. (TDI) diesel generators (Division 1 and 2) has been limited. Division 1 and 2 DGs are operated for 24 hours at a load greater than or equal to the maximum expected post accident load; the first 2 hours of which is at the continuous rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube 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 conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience. Limits on the frequency and voltage during the 24 hour run are unnecessary because this test is performed with the DG connected in parallel to offsite power, and the power factor which is to be maintained is specified.

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

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band for the Division 1 and 2 DGs is provided to avoid routine overloading of these DGs. While this Surveillance allows operation of the Division 1 and 2 DGs in the band of 5600 kW to 7000 kW, a range of 5600 kW to 5800 kW will normally be used in order to minimize wear on the DGs. This is the load range referred to in Note 1. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

The reason for Note 2 is 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 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 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds for Divisions 1 and 2 and 13 seconds for Division 3. The times are derived from the requirements of the accident analysis to respond to a design basis large break LOCA.

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

This SR has been 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 1 hour at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band for the Division 1 and 2 DGs is provided to avoid routine overloading of these DGs. While this Surveillance allows operation of the Division 1 and 2 DGs in the band of 5600 kW to 7000 kW, a range of 5600 kW to 5800 kW will normally be used in order to minimize wear on the DGs. This is the load range

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

referred to in Note 1. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this 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 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), this Surveillance ensures that the manual synchronization and load transfer from the DG to each required offsite power can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the undervoltage 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 auto-close signal on bus undervoltage. Portions of the synchronization circuit are associated with the DG and portions with each offsite circuit. If a failure in the synchronization requirement of the Surveillance occurs, depending on the specific affected portion of the synchronization circuit, either the DG or an associated offsite circuit is declared inoperable.

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

This SR is modified by a Note. This Note is not applicable to Division 3. 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

2) Post 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation 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. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and energization of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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 has been modified by a Note. This Note is not applicable to Division 3. 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 3.8.1.17 (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 maintenance testing that requires performance of portions of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of portions of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment

SR 3.8.1.18

Under accident conditions, loads are sequentially connected to the bus by the time delay relays. The time delay relays control the permissive and starting signals to motor breakers to prevent overloading of the bus power supply due to high motor starting currents. The 10% load sequence time tolerance ensures that sufficient time exists for the bus power supply 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

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 during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (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 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 reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and energization 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

the entire connection and loading sequence is verified. The verification for assuring that the auto-connected emergency loads are energized has a timing requirement associated with Division 3. Thus verification for Division 1 or 2 is simply a check that the auto-connected loads are energized, whereas the verification for Division 3 includes a check that the auto-connected loads are energized in ≤ 13 seconds.

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 being continuously circulated and temperature maintained

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

consistent with manufacturer recommendations for Division 1 and 2 DGs. For the Division 3 DG, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. Note 2 is not applicable to Division 3. 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 plant 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 maintenance testing that requires performance of portions of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to reestablish OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns). Performance of portions of this Surveillance is allowed provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. During operation with 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, plant safety systems. Therefore, this Surveillance shall only be performed during shutdown.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

continuously circulated and temperature maintained consistent with manufacturer recommendations for Division 1 and 2 DGs. For the Division 3 DG, standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15, July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108.
10. Regulatory Guide 1.137.
11. ANSI C84.1, 1982.
12. ASME, Boiler and Pressure Vessel Code, Section XI.
13. IEEE Standard 308.
14. Deleted.

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 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building 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 involving handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

In general, when the unit is shut down the Technical Specifications (TS) 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 loss of 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, and 3 have no specific analyses in MODES 4 and 5. Worst-case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCOs for required systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded.

During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 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 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, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting 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 the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

One offsite circuit supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems-Shutdown," ensures that all required loads are

(continued)

BASES

LCO (continued)

powered from offsite power. An OPERABLE DG, associated with a Division 1 or Division 2 Distribution System Engineered Safety Feature (ESF) bus required OPERABLE by LCO 3.8.8, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Similarly, when the high pressure core spray (HPCS) system is required to be OPERABLE, a separate offsite circuit to the Division 3 Class 1E onsite electrical power distribution subsystem, or an OPERABLE Division 3 DG, ensure an additional source of power for the HPCS. This additional source for Division 3 is not necessarily required to be connected to be OPERABLE. Either the circuit required by LCO Item a, or a circuit required to meet LCO Item c may be connected, with the second source available for connection. Together, OPERABILITY of the required offsite circuit(s) and the ability to manually start a DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling of recently irradiated fuel).

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective ESF bus(es), and accepting required loads during an accident. Qualified offsite circuits are those that are described in the USAR and are part of the licensing basis for the plant. One offsite circuit consists of the Unit 1 startup transformer through the Unit 1 interbus transformer, to the Class 1E 4.16 kV ESF buses through source feeder breakers for each required division. A second acceptable offsite circuit consists of the Unit 2 startup transformer through the Unit 2 interbus transformer, to the Class 1E 4.16 kV ESF buses through source feeder breakers for each required division. Additional path(s) are available, as described in the USAR and the “AC Sources – Operating” Bases.

The required DG must be capable of being manually started, accelerating to rated speed and voltage, and connecting to its respective ESF bus and accepting required loads.

(continued)

BASES

LCO (continued)

It is acceptable for divisions to be cross tied during shutdown conditions, permitting a single offsite power circuit to supply all required AC electrical power distribution subsystems.

As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that the plant will not be in immediate difficulty.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building provide assurance that:

a. Systems that provide core cooling are available;

b. Systems used to mitigate a fuel handling accident involving handling of recently irradiated fuel are available (due to radioactive decay, handling of fuel only requires OPERABILITY of the AC Sources when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours);

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require reactor shutdown.

A.1

A required offsite circuit is considered inoperable if no qualified circuit is supplying power to one required ESF division. If two or more ESF 4.16 kV buses are required per LCO 3.8.8, division(s) with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and movement of recently irradiated fuel.

By allowing the option to declare required features inoperable which are not powered from offsite power, appropriate restrictions can be implemented in accordance with the required feature(s) LCOs' ACTIONS. Required features remaining powered from offsite power (even though that circuit may be inoperable due to failing to power other features) are not declared inoperable by this Required Action.

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3

With the offsite circuit not available to all required divisions, the option still exists 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 and movement of recently irradiated fuel assemblies in the primary containment and fuel handling building. Additionally, crane operations over the spent fuel storage pool shall be suspended when fuel assemblies are stored there.

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 initiate

(continued)

BASES

ACTIONS

A.2.1, A.2.2, A.2.3, B.1, B.2, and B.3 (continued)

action immediately to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Actions for LCO 3.8.8 are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

C.1

When the HPCS System is required to be OPERABLE, and the additional required Division 3 AC source is inoperable, the required diversity of AC power sources to the HPCS System is not available. Since these sources only affect the HPCS System, the HPCS System is declared inoperable and the Required Actions of the affected Emergency Core Cooling Systems LCO entered.

In the event all sources of power to Division 3 are lost, Condition A will also be entered and direct that the ACTIONS of LCO 3.8.8 be taken. If only the Division 3 additional required AC source is inoperable, and power is still supplied to the HPCS System by the circuit meeting the LCO Item a requirement, 72 hours is allowed to restore the additional required AC source to OPERABLE. This is reasonable considering the HPCS System will still perform its function, absent an additional single failure.

(continued)

BASES (continued)

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, and 3. SR 3.8.1.8 is not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.7, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.13, SR 3.8.1.15, SR 3.8.1.18, and SR 3.8.1.19 are not required to be met because DG start and load within a specified time and response on an offsite power or ECCS initiation signal is not required. SR 3.8.1.17 is not required to be met because the required OPERABLE DG(s) is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is not required to be met because starting independence is not required with the DG(s) that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by a Note which precludes requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and preclude de-energizing a required 4160 V ESF bus or disconnecting a required offsite circuit during performance of Surveillances. 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 is required to be OPERABLE. Hence the NOTE provides an exception to SR 3.0.1 during the period when only one diesel generator is OPERABLE.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1 and Ref. 2). The maximum load demand is calculated using the assumption that at least two DGs are 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 each storage tank to its respective day tank by one 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. The fuel oil level in the storage tank is indicated in the control room.

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) and ANSI N195 (Ref. 3) address recommended fuel oil practices, as modified by 1) the ACTIONS and Surveillance Requirements (SRs) of Specification 3.8.3, and 2) the Bases for SR 3.8.3.3, which specifies the current fuel oil testing Standards. The fuel oil properties governed by these SRs include the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level, among others.

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. Each engine lube oil system contains an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has a separate air start system. Each system has two subsystems, each with adequate capacity for five successive starts on the DG without recharging the air start receiver(s).

(continued)

BASES

BACKGROUND (continued)	The Division 1 and 2 DG air start systems have demonstrated sufficient margin during testing such that only one subsystem is required to be OPERABLE in order for the associated DG to be considered OPERABLE. However, testing on the Division 3 DG has demonstrated that one air start subsystem can only marginally provide the necessary motive force to start the DG within the specified start time. Based on these marginal test results, both subsystems are required to be OPERABLE for the Division 3 DG to be considered OPERABLE.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 6 (Ref. 4) and 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, and starting air subsystems support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load, i.e., maximum expected post LOCA load, operation. It is also required to meet specific standards for quality. Additionally, sufficient lube 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 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 starting air system is required to have a minimum capacity for five successive DG starts without recharging the air start receivers. Division 1, 2, and 3 have two independent air start subsystems per DG. For Division 1 and 2 DGs, one air start subsystem for an engine is required for OPERABILITY of each DG. For the Division 3 DG, two air start subsystems are required for OPERABILITY.

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

(continued)

BASES

APPLICABILITY (continued)

after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air 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 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 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. The fuel oil level equivalent to a 6 day supply for Division 1 and Division 2 is 65,100 gallons each and for Division 3 is 32,000 gallons. These circumstances may be caused by events such as:

a. Full load operation required after an inadvertent start while at minimum required level; or

b. Feed and bleed operations that 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 the 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 (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

In this Condition, the 7 day lube oil inventory, i.e., sufficient lube oil to support 7 days of continuous DG operation at full load conditions, is not available. However, the

(continued)

BASES

ACTIONS

B.1 (continued)

Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. The lube oil level equivalent to a 6 day supply for Division 1 and Division 2 is 350 gallons each and for Division 3 is 236 gallons. This restriction allows sufficient time for obtaining 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.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since 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, to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination 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 high likelihood that the DG would still be capable of performing its intended function.

(continued)

BASES

ACTIONS (continued)

E.1

With the required starting air receiver pressure < 210 psig, sufficient capacity for five successive DG start attempts may not exist. However, as long as the receiver pressure is ≥ 165 psig for Division 1, 2, and 3, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit.

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.

F.1

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through E, 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 each DG's operation for 7 days at maximum expected post LOCA loading. The fuel oil level equivalent to a 7 day supply for Division 1 and 2 is 73,700 gallons each and for Division 3 is 36,700 gallons when calculated in accordance with References 2 and 3. The required fuel storage volume is determined using the most limiting energy content of the stored fuel. Using the known correlation of diesel fuel oil absolute specific gravity or API gravity to energy content, the required diesel generator output, and the corresponding fuel consumption rate, the onsite fuel storage volume required for 7 days of operation can be determined. SR 3.8.3.3 requires new fuel to be tested to verify that the absolute specific gravity or API gravity is within the range assumed in the diesel fuel oil consumption calculations. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of maximum expected post LOCA load operation for each DG. The lube oil level equivalent to a 7 day supply for Division 1 and Division 2 is 374 gallons each and for Division 3 is 260 gallons and is based on the DG manufacturer's consumption values for the run time of the DG. The 7 day lube oil inventory for the Division 1 and 2 diesel engines represents the minimum volume of lube oil required to safely sustain engine operation (sump tank oil level above the lube oil pump suction foot valve) plus the volume of lube oil that would be consumed during 7 days of continuous operation. The 7 day lube oil inventory limit for the Division 3 diesel engine represents the minimum volume of lube oil required to safely sustain engine operation (sump tank oil level at dipstick low level) plus the volume of lube oil that would be consumed during 7 days of continuous operation.

The lube oil sump inventories identified herein correspond to the following lube oil sump tank dipstick readings:

Division 1 and 2
374 Gallons – 3 1/2" above the dipstick LOW mark
350 Gallons – 1 1/2" above the dipstick LOW mark

Division 3
260 Gallons – 4 3/8" below dipstick HIGH mark
236 Gallons – 5 1/2" below dipstick HIGH mark

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

SR 3.8.3.3

This Surveillance ensures that fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program, and ensures the availability of high quality fuel oil for the DGs. The Diesel Fuel Oil Testing Program includes testing to determine API gravity or an absolute specific gravity, flash point and kinematic viscosity, water and sediment content, and total particulate concentration, and that new fuel is within limits for ASTM 2D fuel oil. Testing is performed in accordance with applicable ASTM Standards. Specific test frequencies are discussed in the Diesel Fuel Oil Testing program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

Failure to meet the new fuel oil limits for fuel that has not been added to the storage tanks is not a failure of this SR or failure to meet the LCO.

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 particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the air compressor, sufficient air start capacity for each DG is available. The system design provides for a minimum of five engine starts without recharging. The pressure specified in this SR reflects the value at which the five starts can be accomplished but is not so high as to result in failing the limit due to normal cycling of the air compressor. Division 1, 2, and 3 DGs have two independent air start subsystems per DG. For Division 1 and 2 DGs, this Surveillance is met provided one air start receiver for an engine is pressurized ≥ 210 psig. For Division 3 DG, this Surveillance is met provided two air start receivers are pressurized ≥ 210 psig. 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. Periodic removal of water from the 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, rainwater, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES

1. USAR, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195 - 1976.
4. USAR, Chapter 6.
5. USAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources – Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of three independent Class 1E DC electrical power subsystems, Divisions 1, 2, and 3. Each subsystem consists of a battery, a battery charger, a reserve battery charger, and all the associated control equipment and interconnecting cabling. In addition, the ability exists to tie in the Unit 2 batteries in each division to their respective Unit 1 buses.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the Engineered Safety Feature (ESF) batteries.

Each of the Division 1 and 2 electrical power subsystems provides the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. The Division 3 DC electrical power subsystem provides DC motive and control power as required for the High Pressure Core Spray (HPCS) System diesel generator (DG) set control and protection.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution Systems – Operating," and LCO 3.8.8, "Distribution Systems – Shutdown."

(continued)

BASES

BACKGROUND (continued)

Each DC subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

Each battery has adequate storage capacity to meet the duty cycles discussed in the USAR, Section 8 (Ref. 4). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for a DC electrical power subsystem are sized to produce required capacity at 80% of nameplate rating. The minimum voltage design limit is 1.875 V per cell for Division 1, 1.863 V per cell for Division 2 and 1.905 V per cell for Division 3 batteries (Ref. 4).

The battery cells are flooded lead acid construction with a nominal specific gravity of 1.215. This specific gravity corresponds to an open circuit battery voltage of approximately 125 V for a 61 cell battery for Division 1 and a 60 cell battery for Division 2 and Division 3 (i.e., cell voltage of 2.049 volts per cell (Vpc) for Division 1 and cell voltage of 2.083 Vpc for Division 2 and Division 3)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.049 Vpc, the Division 1 battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Likewise, once fully charged with its open circuit voltage ≥ 2.083 Vpc, the Division 2 battery cell and Division 3 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 of 2.17 to 2.26 Vpc for Division 1 and 2 batteries, and 2.20 to 2.25 Vpc for Division 3 batteries. This provides adequate over-potential, which limits the formation of lead sulfate and self-discharge. The nominal float voltage of 2.21 Vpc for Division 1 and 2.25 Vpc for Division 2 and Division 3 corresponds to a total float voltage output of 135 V for a 61/60 cell battery as discussed in the USAR, Section 8 (Ref. 4).

Each battery charger of Division 1 and 2 DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient excess capacity to restore the battery bank from the design minimum charge to its fully charged state within 12 hours while supplying normal steady state loads (Ref. 4).

(continued)

BASES

BACKGROUND (continued)

The battery charger of Division 3 DC electrical power subsystem battery charger has sufficient excess capacity to restore the battery bank from the design minimum charge to its fully charged state in 8 hours while supplying normal steady state loads (Ref. 4).

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery performance test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 5) and Chapter 15 (Ref. 6), assume that 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or of all onsite AC power; and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

The DC electrical power subsystems, each subsystem consisting of either the Unit 1 or 2 battery, either the normal or reserve battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the divisions, 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 DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

Division 1 consists of:
1. 125 volt battery 1R42-S002 or 2R42-S002.
2. 125 volt full capacity charger 1R42-S006 or 0R42-S007.

Division 2 consists of:
1. 125 volt battery 1R42-S003 or 2R42-S003.
2. 125 volt full capacity charger 1R42-S008 or 0R42-S009.

Division 3 consists of:
1. 125 volt battery 1E22-S005 or 2E22-S005.
2. 125 volt full capacity charger 1E22-S006 or 0R42-S011.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 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

(continued)

BASES

APPLICABILITY (continued)

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 4 and 5 are addressed in the Bases for LCO 3.8.5, “DC Sources – Shutdown.”

ACTIONS

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

Condition A represents one subsystem with required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristics of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as a result of the inoperable battery charger, it is now fully capable of supplying the maximum expected load requirement. The 2 amp value is based on returning the battery for Division 1 to 92% charge, the battery for Division 2 to 96% charge, and the battery for Division 3 to 95% charge, and assumes a 5% design margin for the battery. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1

Condition B represents one subsystem with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected subsystem. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system subsystem.

(continued)

BASES

ACTIONS

B.1 (continued)

If one of the required Division 1 or 2 DC electrical power subsystems is inoperable for reasons other than Condition A (e.g., inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems 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 minimum necessary DC electrical subsystems, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1

With the Division 3 DC electrical power subsystem inoperable, the HPCS System may be incapable of performing its intended function and must be immediately declared inoperable. This declaration also requires entry into applicable Conditions and Required Actions of LCO 3.5.1, “ECCS – Operating.”

D.1 and D.2

If the DC electrical power subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 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. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the 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, 2.17 Vpc for Division 1 and 2, and 2.20 Vpc for Division 3, times the number of connected cells. This voltage maintains the battery plates in a condition that supports maintaining the grid life. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2

This SR verifies the design capacity of the battery chargers. According to Regulatory Guide 1.32 (Ref. 8), the battery charger 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 demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

This SR provides two options. One option requires that each battery charger be capable of supplying 400 amps for Division 1 and 2 and 50 amps for Division 3 at the minimum established float voltage for 8 hours. The ampere requirements are based on the output rating of the chargers. The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a performance test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the battery performance test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

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

This SR is modified by a Note. The Note allows the periodic performance of SR 3.8.6.6 in lieu of SR 3.8.4.3. This substitution is acceptable because SR 3.8.6.6 represents a more severe test of battery capacity than SR 3.8.4.3.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. USAR, Section 8.
5. USAR, Chapter 6.
6. USAR, Chapter 15.
7. Regulatory Guide 1.93, December 1974.
8. Regulatory Guide 1.32, February 1977.
9. Regulatory Guide 1.129, December 1974.

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 USAR, 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 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building ensures that: a. The facility 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 involving handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours. The DC sources satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	One DC electrical power subsystem (consisting of either the Unit 1 or 2 battery, either the normal or reserve battery charger, and all the associated control equipment and interconnecting cabling supplying power to the associated

(continued)

BASES

LCO (continued)

bus), associated with the Division 1 or Division 2 onsite Class 1E DC electrical power distribution subsystem(s) required OPERABLE by LCO 3.8.8, "Distribution Systems – Shutdown," is required to be OPERABLE. Similarly, when the High Pressure Core Spray (HPCS) System is required to be OPERABLE, the Division 3 DC electrical power subsystem associated with the Division 3 onsite Class 1E DC electrical power distribution subsystem required OPERABLE by LCO 3.8.8 is required to be OPERABLE. In addition to the preceding subsystems required to be OPERABLE, a Class 1E battery or battery charger and the associated control equipment and interconnecting cabling capable of supplying power to the remaining Division 1 or Division 2 onsite Class 1E DC electrical power distribution subsystem, when portions of both Division 1 and Division 2 DC electrical power distribution subsystems are required to be OPERABLE by LCO 3.8.8. This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling of recently irradiated fuel).

Division 1 consists of:
1. 125 volt battery 1R42-S002 or 2R42-S002.
2. 125 volt full capacity charger 1R42-S006 or 0R42-S007.

Division 2 consists of:
1. 125 volt battery 1R42-S003 or 2R42-S003.
2. 125 volt full capacity charger 1R42-S008 or 0R42-S009.

Division 3 consists of:
1. 125 volt battery 1E22-S005 or 2E22-S005.
2. 125 volt full capacity charger 1E22-S006 or 0R42-S011.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment and fuel handling building provide assurance that:

a. Required features to provide core cooling are available;

(continued)

BASES

APPLICABILITY (continued)	b.	Required features used to mitigate a fuel handling accident involving handling of recently irradiated fuel are available (due to radioactive decay, handling of fuel only requires OPERABILITY of the DC Sources when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours);

(continued)

BASES

APPLICABILITY (continued)

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

The ACTIONS are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require reactor shutdown.

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

Condition A represents one subsystem with the required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle.

The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

(continued)

BASES

ACTIONS

A.1, A.2, and A.3 (continued)

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting modes, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1, B.2.1, B.2.2, and B.2.3

If more than one DC distribution subsystem is required according to LCO 3.8.8, the DC subsystems remaining OPERABLE with one or more DC power sources inoperable may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and

(continued)

BASES

ACTIONS

B.1, B.2.1, B.2.2, and B.2.3 (continued)

movement of recently irradiated fuel. By allowing the option to declare required features associated with an inoperable DC power source(s) inoperable, appropriate restrictions are implemented in accordance with the Required Actions of the LCOs for these associated required features. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative alternate actions (i.e., to suspend CORE ALTERATIONS and movement of recently irradiated fuel assemblies in the primary containment and fuel handling building) is made.

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 DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant 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 actual performance is not required.

REFERENCES

1. USAR, Chapter 6.
2. USAR, 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 5.5.16 for monitoring various battery parameters.

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 125 V for 61 cell battery for Division 1 and a 60 cell battery for Division 2 and Division 3 (i.e., cell voltage of 2.049 volts per cell (Vpc) for Division 1 and cell voltage of 2.083 Vpc for Division 2 and 3)). The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged with its open circuit voltage ≥ 2.049 Vpc, the Division 1 battery cell will maintain its capacity for 30 days without further charging per manufacturer's instructions. Likewise, once fully charged with its open circuit voltage ≥ 2.083 Vpc, the Division 2 battery cell and Division 3 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 of 2.17 to 2.26 Vpc for Division 1 and 2 batteries, and 2.20 to 2.25 Vpc for Division 3 batteries. This provides adequate over-potential which limits the formation of lead sulfate and self-discharge. The nominal float voltage of 2.21 Vpc for Division 1 and 2.25 Vpc for Division 2 and Division 3 corresponds to a total float voltage output of 135 V for a 61/60 cell battery as discussed in the USAR, Section 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 6 (Ref. 3) and Chapter 15 (Ref. 4), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one subsystem of DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Since battery parameters support the operation of the DC power sources, they satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.16.

APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystem. 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

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each battery. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable battery. Complying with the Required Actions for one inoperable battery may allow for continued operation, and subsequent inoperable batteries are governed by separate Condition entry and application of associated Required Actions.

(continued)

BASES

ACTIONS (continued)

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

With one or more cells in one or more batteries in one subsystem ≤ 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries ≤ 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. If SR 3.8.6.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1 and B.2

One or more batteries in one subsystem with float > 2 amps indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. TS 3.8.4 Condition A and TS 3.8.5 Condition A addresses 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 or equal to 2.07 V, the associated

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

"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 or equal to 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.

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 or more batteries in one subsystem 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 5.5.16, 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

(continued)

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.16.b item to initiate action to equalize and test in accordance with manufacturer's recommendation. 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 batteries may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries in one subsystem with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With one or more batteries in redundant subsystems with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one subsystem within 2 hours.

F.1

When any battery parameter is 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 associated battery must be declared inoperable. Additionally, discovering one or more batteries in one subsystem with one or more battery cells float voltage less than or equal to 2.07 V and float current greater than 2 amps indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

(continued)

BASES (continued)

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 equipment used to monitor float current must have the necessary accuracy and capability to measure electrical currents in the expected range. The float current requirements are based on the float current indicative of a charged battery. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 132.37 Vdc for Division 1, 130.2 Vdc for Division 2, and 132 Vdc for Division 3 at the battery terminals, or 2.17 Vpc for Division 1 and 2, and 2.20 Vpc for Division 3. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.16. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are 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 minimum design electrolyte level is the minimum level indication mark on the battery cell jar. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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., 72°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

The battery performance discharge test is acceptable for satisfying SR 3.8.6.6.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. Furthermore, the battery is sized to meet the assumed duty cycle loads when the battery design capacity reaches this 80% limit. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is 10% below the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.6 (continued)

This SR is modified by a Note. Credit may be taken for unplanned events that satisfy this SR. This note is provided to prevent unnecessary cycling of plant equipment.

REFERENCES

1. IEEE-450.
2. USAR, Chapter 8.
3. USAR, Chapter 6.
4. USAR, Chapter 15.
5. IEEE Standard 485, 1983.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems – Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution systems are divided by division into three independent AC and DC electrical power distribution subsystems.

The primary AC distribution system consists of each 4.16 kV Engineered Safety Feature (ESF) bus that 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 source. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses. The DC distribution system provides control power for the 4.16 kV breakers which 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 plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers.

The Class 1E 120 VAC buses/distribution panels provide power to ESF and RPS instrumentation and controls. Division 1 supplies power to EB-1-A1, EK-1-A1, and EV-1-A. Division 2 supplies power to EB-1-B1, EK-1-B1, and EV-1-B. Division 3 supplies power to EK-1-C. One bus in Division 1 (EV-1-A) and one bus in Division 2 (EV-1-B) are normally powered from the respective divisional Class 1E battery through an inverter. The alternate power supplies for these two buses are Class 1E constant voltage source transformers powered from the same division as the associated inverter. However, if the inverter supply becomes inoperable or required maintenance or plant operations dictate, the alternate power supply is used. The only loads that affect safety on these buses are the LPRM/APRM instrumentation power. Although continuous power is desirable for these instruments, a loss of power to the instrument buses would cause the required safety functions to occur. Therefore, having one or both of these buses powered from their alternate supplies for even extended periods of time would not result in a decrease in safety.

(continued)

BASES

BACKGROUND (continued)	There are three independent 125 VDC electrical power distribution subsystems. The list of distribution buses is located in Table B 3.8.7-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC and DC 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 and DC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant (Ref. 4). This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite or onsite AC electrical power; and

b. A worst case single failure.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required AC and DC power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC 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 Division 1, 2, and 3 AC and DC electrical power primary distribution subsystems are required to be OPERABLE. Maintaining the Division 1, 2, and 3 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Any two of the three divisions of the

(continued)

BASES

LCO (continued)

distribution system are capable of providing the necessary electrical power to the associated ESF components. Therefore, a single failure within any system or within the electrical power distribution subsystems does not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses to be energized to their proper voltages.

OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger.

In addition, tie breakers between redundant safety related AC and DC 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, which 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. 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.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 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.

A Note has been added taking exception to the Applicability requirements for the Division 3 electrical power distribution subsystems, provided the HPCS System is declared inoperable. This exception is intended to allow declaring of the HPCS System inoperable either in lieu of declaring the Division 3 electrical power distribution subsystems inoperable, or at any time subsequent to entering

(continued)

BASES

APPLICABILITY (continued)

ACTIONS for an inoperable Division 3 electrical power distribution subsystem. This exception is acceptable since, with the HPCS System inoperable and the associated ACTIONS entered, the Division 3 electrical power distribution subsystems provide no additional assurance of meeting the above criteria.

Electrical power distribution subsystem requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more Division 1 or 2 required AC buses, load centers, motor control centers, or distribution panels, in one division inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining AC electrical 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.

The Condition A worst case scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit, and on restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

(continued)

BASES

ACTIONS

A.1 (continued)

a. There is potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with performing a unit shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required AC and DC electrical power distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 2 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC bus could again become inoperable, and AC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition A was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

B.1

With one or more Division 1 or 2 DC electrical power distribution subsystems inoperable, the remaining DC electrical power distribution subsystems are 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

(continued)

BASES

ACTIONS

B.1 (continued)

reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystems must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger. For MCC ED-1-A-09, an alternative to this action is to declare the Reactor Core Isolation Cooling (RCIC) System inoperable, since the only system supplied power from this MCC that has Technical Specification importance is the RCIC System. If this option is used, the necessary actions for declaring RCIC inoperable must be taken.

Condition B may represent one division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the unit operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that could be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, that would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

b. The potential for decreased safety when requiring entry into numerous applicable Conditions and Required Actions for components without DC power while not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected division; and

(continued)

BASES

ACTIONS

B.1 (continued)

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).

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required AC and DC electrical power distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC bus could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

C.1 and C.2

If the inoperable electrical power distribution subsystem cannot be restored to OPERABLE status within the associated 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 12 hours and to MODE 4 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

ACTIONS (continued)

D.1

With one or more Division 3 AC or DC electrical power distribution subsystems inoperable, the Division 3 powered systems are not capable of performing their intended functions. Immediately declaring the HPCS System inoperable allows the ACTIONS of LCO 3.5.1, “ECCS-Operating,” to apply appropriate limitations on continued reactor operation.

E.1

Condition E corresponds to a level of degradation in the electrical distribution system that causes a required safety function to be lost. When more than one Condition is entered, and this results in the loss of a required function, the plant is in a condition outside the accident analysis. Therefore, no additional time is justified for continued operation. LCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

Meeting this Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. USAR, Chapter 6.
2. USAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.
4. USAR, Section 8.3.

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	NOMINAL VOLTAGE	DIVISION 1 (a)	DIVISION 2 (a)	DIVISION 3 (a)
AC Electrical Power Distribution System	4160 V	EH11	EH12	EH13
	480 V LCCs	EF-1-A EF-1-B	EF-1-C EF-1-D	---
	480 V MCCs	EF-1-A-07 EF-1-A-08 EF-1-A-09 EF-1-A-12 EF-1-B-07 EF-1-B-08 EF-1-B-09	EF-1-C-07 EF-1-C-08 EF-1-C-09 EF-1-C-12 EF-1-D-07 EF-1-D-08 EF-1-D-09	EF-1-E-1 EF-1-E-2
	120 V Dist. Panels	EB-1-A1 EK-1-A1	EB-1-B1 EK-1-B1	EK-1-C1
	120 V Bus	EV-1-A	EV-1-B	---
DC Electrical Power Distribution System	125 V	Bus ED-1-A	Bus ED-1-B	Bus ED-1-C
	MCCs	ED-1-A-09	---	---
	Dist. Panels	ED-1-A-06	ED-1-B-06 ED-1-B-08	1R42-S037

(a) Each division of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems - Shutdown

BASES

BACKGROUND	A description of the AC and DC electrical power distribution systems is provided in the Bases for LCO 3.8.7, "Distribution Systems-Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the USAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC 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 and DC electrical power distribution systems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building ensures that:

a. The facility 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 involving handling of recently irradiated fuel, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

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 AC and DC electrical power distribution systems necessary to support OPERABILITY of Technical Specifications' required systems, equipment, and components-both specifically addressed by their own LCOs, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the AC and DC electrical power distribution systems energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling of recently irradiated fuel).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the primary containment or fuel handling building provide assurance that:

a. Required features needed that provide core cooling are available;

b. Required features used to mitigate a fuel handling accident involving handling of recently irradiated fuel are available (due to radioactive decay, handling of fuel only requires OPERABILITY of the Distribution Systems when the fuel being handled is recently irradiated, i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours);

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require reactor shutdown.

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and movement of recently irradiated fuel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the Required Actions of the LCOs for these associated required features. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS and movement of recently irradiated fuel assemblies in the primary containment and fuel handling building).

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 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 plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal – shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS

(continued)

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

would not be entered. Therefore, Required Action A.2.4 is provided to direct declaring the associated required shutdown cooling subsystems inoperable, and not in operation, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC and DC electrical power distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the required AC and DC electrical power distribution subsystems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures that 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 required 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. USAR, Chapter 6.
2. USAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce unit procedures in preventing the reactor from achieving criticality during refueling. The refueling equipment interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided. The following provide input to one or both channels: the position of the refueling platform, the loading of the refueling platform main hoist, and the full insertion of all control rods. With the reactor mode switch in the shutdown or refueling position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform and the fuel grapple are physically located over the reactor vessel. The main hoist has two switches that open when the hoist is loaded with fuel. The refueling interlocks use these indications to prevent

(continued)

BASES

BACKGROUND (continued)	operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2). The hoist switches open at a load lighter than the weight of a single fuel assembly in water.
APPLICABLE SAFETY ANALYSES	The refueling equipment interlocks are explicitly assumed in the USAR analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling equipment interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a control rod from the core during fuel loading. The refueling platform location switches activate at a point outside of the reactor core, such that, considering switch hysteresis and maximum platform momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core. Refueling equipment interlocks satisfy Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	To prevent criticality during refueling, the refueling equipment interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn. To prevent these conditions from developing, the all-rods-in, the refueling platform position, and the refueling platform main hoist fuel loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment interlocks or control rod blocks to prevent operations that could result in criticality during refueling operations.

(continued)

BASES (continued)

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is installed, and no fuel loading activities are possible. Therefore, the refueling equipment interlocks are not required to be OPERABLE in these MODES.

ACTIONS

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

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply (Required Action A.1) or the interlocks are not needed (Required Action A.2).

Therefore, Required Action A.1 requires that in-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

Alternatively, Required Actions A.2.1 and A.2.2 will permit continued fuel movement with the interlocks inoperable if a control rod withdrawal block is inserted and all control rods are subsequently verified to be fully inserted. Required Action A.2.1 (rod block) ensures that no control rods can be withdrawn. The withdrawal block utilized must ensure that if rod withdrawal is requested, the rod will not respond (i.e., it will remain inserted). Required Action A.2.2 is performed after placing the rod withdrawal block in effect, and provides a verification that all control rods are fully inserted. This verification that all control rods are fully inserted is in addition to the periodic verifications required by SR 3.9.3.1. As part of the "all control rods inserted" check, the operator must ensure that false "full-in" indications do not exist due to bypassed "full-in" indicators.

(continued)

BASES

ACTIONS

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

Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure that unacceptable operations are blocked (e.g., loading fuel into a cell with the control rod withdrawn). One use for the A.2 Required Actions is to permit performance of SR 3.9.1.1 once, prior to fuel movement, without the need for subsequent performance if the fuel movement period extends longer than the periodic Frequency of the SR. This permits continued fuel movement under the protection of the continuous rod block inserted by the Actions.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

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

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. USAR, Section 7.7.1.6.
3. USAR, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND

The refuel position one-rod-out interlock restricts the withdrawal of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Rod Control and Information System).

This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refuel position one-rod-out interlock is explicitly assumed in the USAR analysis of the control rod withdrawal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The refuel position one-rod-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") prevent criticality by preventing withdrawal of more than one control rod. With one control rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion.

The refuel position one-rod-out interlock satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

LCO

To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. At least one channel of the refuel position one-rod-out interlock is required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of these channels.

APPLICABILITY

In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions.

In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and the control rods (LCO 3.1.3, "Control Rod OPERABILITY") provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A.1 and A.2

With the refuel position one-rod-out interlock inoperable, the refueling interlocks are not capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality.

Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refuel position one-rod-out interlock requires the reactor mode switch to be in refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refuel position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

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

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, this SR has been modified

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.2.2 (continued) by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. USAR, Section 7.7.1.6. 3. USAR, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND

Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation").

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1).

The safety analysis of the control rod withdrawal error during refueling (Ref. 2) assumes the proper functioning of the refueling interlocks and adequate SDM.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Additionally, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality. Control rod position satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.
APPLICABILITY	During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn. In MODES 1, 2, 3, and 4, the reactor pressure vessel head is installed, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.
ACTIONS	A.1 With all control rods not fully inserted when loading fuel assemblies into the core, an inadvertent criticality could occur that is not analyzed in the USAR. All in-core fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.3.1 During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.9.3 1</u> (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. USAR Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel for each control rod provides information necessary to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") use the full-in position indication channel to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position indication channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the selection of any other control rod.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) assumes the proper functioning of the refueling interlocks and adequate SDM. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time.

Control rod position indication satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO

One control rod full-in position indication channel for each control rod must be OPERABLE to provide the required inputs to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling equipment interlock all-rods-in logic (LCO 3.9.1), and correct position indication to at least one channel of the refuel position one-rod-out interlock logic (LCO 3.9.2). For the refueling equipment interlock all-rods-in logic the required full-in position indication channel for each control rod is Channel 1. At all other times (when the refueling equipment interlocks are not required to be OPERABLE) either Channel 1 or Channel 2 OPERABILITY for each control rod satisfies the LCO.

APPLICABILITY

During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

A Note has been provided to modify the ACTIONS related to control rod position indication channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable control rod position indication channels provide appropriate compensatory measures for separate inoperable channels. As such, this Note has been provided, which allows separate Condition entry for each inoperable required control rod position indication channel.

(continued)

BASES

ACTIONS (continued)

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With one or more required full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions may be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicators(s) and to disarm the drive(s) to ensure that the control rod is not withdrawn. Actions must continue until all associated control rods are fully inserted and drives are disarmed. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in position indication channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are activated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. The full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn is considered adequate because of

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.9.4.1</u> (continued) the procedural controls on control rod withdrawals and the indications available in the control room to alert the operator to control rods not fully inserted.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. USAR, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY-Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

The safety analysis for the control rod withdrawal error during refueling (Ref. 2) evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur.

Control rod OPERABILITY during refueling satisfies Criterion 3 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).

(continued)

BASES (continued)

LCO	Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is ≥ 1520 psig and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore are not required to be OPERABLE.
APPLICABILITY	During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical. For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." In MODES 3 and 4, with the reactor mode switch in the shutdown position a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions. This provides adequate requirements for control rod OPERABILITY during these conditions.
ACTIONS	<u>A.1</u> With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable withdrawn control rod(s). Inserting the control rod(s) ensures that the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable withdrawn control rod(s) is fully inserted.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.5.1 and SR 3.9.5.2</u> During MODE 5, the OPERABILITY of control rods is primarily required to ensure that a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is ≥ 1520 psig.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.5.1 and SR 3.9.5.2 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. USAR, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level-Irradiated Fuel

BASES

BACKGROUND

The movement of irradiated fuel assemblies within the RPV requires a minimum water level of 22 ft 9 inches above the top of the RPV flange. During refueling, this maintains a sufficient water level in the upper containment pool. Sufficient water is necessary to retain halogen (e.g., iodine) fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient halogen activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 50.67 limits, as provided by the guidance of Reference 1.

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.183 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for halogens. This relates to the assumption that 99.5% of the total halogens released from the pellet to cladding gap of all the dropped fuel assembly rods are retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 8% of the total fuel rod I-131 inventory and 5% of the other halogens (Ref. 1).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 23 ft over irradiated assemblies in the RPV and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 4).

While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	assembly, dropping an assembly on the RPV flange will result in reduced releases of fission gases. Based on this judgment, and the physical dimensions which preclude normal operation with water level 23 feet above the flange, a slight reduction in this water level is acceptable. RPV water level satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	A minimum water level of 22 ft 9 inches above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 1.
APPLICABILITY	LCO 3.9.6 is applicable during movement of irradiated fuel assemblies within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. Requirements for handling of new fuel assemblies or control rods (where water depth to the RPV flange is not of concern) are covered by LCO 3.9.7, "RPV Water - New Fuel or Control Rods." Requirements for fuel handling accidents in the spent fuel storage pools and upper fuel storage pool are covered by LCO 3.7.7, "Fuel Pool Water Level."
ACTIONS	<u>A.1</u> If the water level is < 22 ft 9 inches above the top of the RPV flange, all operations involving movement of irradiated fuel assemblies within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of irradiated fuel movement shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.6.1</u> Verification of a minimum water level of 22 ft 9 inches above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.6.1 (continued) during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. Regulatory Guide 1.183, July 2000. 2. USAR, Section 15.7.6. 3. Deleted 4. 10 CFR 50.67.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Reactor Pressure Vessel (RPV) Water Level-New Fuel or Control Rods

BASES

BACKGROUND

The movement of new fuel assemblies or handling of control rods within the RPV when fuel assemblies seated within the reactor vessel are irradiated requires a minimum water level of 23 ft above the top of irradiated fuel assemblies seated within the RPV. During refueling, this maintains a sufficient water level above the irradiated fuel. Sufficient water is necessary to retain halogen (e.g., iodine) fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient halogen activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 50.67 limits, as provided by the guidance of Reference 1.

APPLICABLE SAFETY ANALYSES

During movement of new fuel assemblies or handling of control rods over irradiated fuel assemblies, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.183 (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for halogens. This relates to the assumption that 99.5% of the total halogens released from the pellet to cladding gap of all the dropped fuel assembly rods are retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 8% of the total fuel rod I-131 inventory and 5% of the other halogens (Ref. 1).

Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 23 ft over irradiated assemblies in the RPV and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 4).

The related assumptions include the worst case dropping of an irradiated fuel assembly onto the reactor core loaded with irradiated fuel assemblies.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RPV water level satisfies Criterion 2 of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132).
LCO	A minimum water level of 23 ft above the top of irradiated fuel assemblies seated within the RPV is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 1.
APPLICABILITY	LCO 3.9.7 is applicable when moving new fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) over irradiated fuel assemblies seated within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, 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 storage pools and upper fuel storage pool are covered by LCO 3.7.7, "Fuel Pool Water Level." Requirements for handling irradiated fuel over the RPV are covered by LCO 3.9.6, "Reactor Pressure Vessel (RPV) Water Level-Irradiated Fuel."
ACTIONS	<u>A.1</u> If the water level is < 23 ft above the top of irradiated fuel assemblies seated within the RPV, all operations involving movement of new fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.7.1</u> Verification of a minimum water level of 23 ft above the top of the irradiated fuel assemblies seated within the RPV ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1 (continued)

met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2).

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

REFERENCES

1. Regulatory Guide 1.183, July 2000.
2. USAR, Section 15.7.6.
3. Deleted
4. 10 CFR 50.67.

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR-High Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of one motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines or to the upper containment pool or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Emergency Service Water System. In addition to the above RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.
APPLICABLE SAFETY ANALYSES	With the unit in MODE 5, the RHR System in the shutdown cooling mode is not required for mitigation of any events or accidents evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR System in the shutdown cooling mode does not meet a specific criterion of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132), it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR System in the shutdown cooling mode is retained as a Specification.
LCO	Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with irradiated fuel in the RPV and with the water level ≥ 22 ft 9 inches above the RPV flange, and heat losses to the ambient are not sufficient to maintain average reactor coolant temperature ≤ 140°F. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

(continued)

BASES

LCO (continued)

An RHR shutdown cooling subsystem is OPERABLE when the RHR pump, two heat exchangers in series, valves, piping, instrumentation, and controls are OPERABLE.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow the required RHR shutdown cooling subsystem to be removed from operation for up to two hours in an eight hour period.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE in MODE 5, with the water level ≥ 22 ft 9 inches above the top of the RPV flange, when heat losses to the ambient are not sufficient to maintain average reactor coolant temperature ≤ 140°F, to provide decay heat removal. Ambient losses must be such that no increase in reactor vessel water temperature will occur. With RPV water temperature remaining below 140°F, adequate margin is being maintained to coolant boiling, evaporative losses are minimal, and refueling floor environmental conditions will not be adversely affected. If temperature is not maintained below this value with only ambient heat losses, decay heat removal capability is required. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems. RHR Shutdown Cooling System requirements in MODE 5, with irradiated fuel in the RPV and with the water level < 22 ft 9 inches above the RPV flange, are given in LCO 3.9.9, "Residual Heat Removal (RHR) – Low Water Level."

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be established within 1 hour. In this condition, the volume of water above

(continued)

BASES

ACTIONS

A.1 (continued)

the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

The required cooling capacity of the alternate method should be sufficient to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Fuel Pool Cooling and Cleanup System, the Reactor Water Cleanup System, the Alternate Decay Heat Removal System (ADHR), or an inoperable but functional RHR shutdown cooling subsystem.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend operations involving an increase in reactor decay heat load by suspending the loading of irradiated fuel assemblies into the RPV.

Additional actions are required to be initiated immediately to minimize any potential fission product release to the environment. This includes ensuring primary containment is OPERABLE and primary containment isolation capability (i.e., one closed door in each primary containment air lock, and at least one primary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the

(continued)

BASES

ACTIONS

B.1, B.2, B.3, and B.4 (continued)

component to OPERABLE status. In addition, at least one door in each primary containment air lock must be closed. The closed air lock door completes the boundary for control of potential radioactive releases. With the appropriate administrative controls however, the closed door can be opened intermittently for entry and exit. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the door except during the entry and exit, and assuring the door is closed after completion of the containment entry and exit. This allowance is acceptable due to the need for containment access and due to the slow progression of events which may result from inadequate decay heat removal. Loss of decay heat removal would not be expected to result in the immediate release of appreciable fission products to the containment atmosphere. Actions must continue until all requirements of this Condition are satisfied.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation except as permitted by the LCO Note, an alternate method of reactor coolant circulation is required to be established within 1 hour. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of reactor coolant circulation by the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.9.8.1 This Surveillance verifies that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	None.

B 3.9 REFUELING OPERATIONS

B 3.9.9 Residual Heat Removal (RHR-Low Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. The two redundant, manually controlled shutdown cooling subsystems of the RHR System promote decay heat removal function. Each loop consists of one motor driven pump, two heat exchangers in series, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via separate feedwater lines, or to the upper containment pool or to the reactor via the low pressure coolant injection path. The RHR heat exchangers transfer heat to the Emergency Service Water System.
APPLICABLE SAFETY ANALYSES	With the unit in MODE 5, decay heat removal by the RHR System in the shutdown cooling mode is not required for mitigation of any events or accidents evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. Although the RHR System in the shutdown cooling mode does not meet a specific criterion of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132), it was identified in the NRC Policy Statement as a significant contributor to risk reduction. Therefore, the RHR System in the shutdown cooling mode is retained as a Specification.
LCO	In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and with the water level < 22 ft 9 inches above the RPV flange and heat losses to the ambient are not sufficient to maintain average reactor coolant temperature ≤ 140°F, both RHR shutdown cooling subsystems must be OPERABLE. An RHR shutdown cooling subsystem is OPERABLE when the RHR pump, two heat exchangers in series, valves, piping, and instrumentation and controls are OPERABLE.

(continued)

BASES

LCO (continued)

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow the required RHR shutdown cooling subsystem to be removed from operation for up to two hours in an eight hour period.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE in MODE 5, with irradiated fuel in the RPV and with the water level < 22 ft 9 inches above the top of the RPV flange, when heat losses to the ambient are not sufficient to maintain average reactor coolant temperature ≤ 140°F, to provide decay heat removal. Ambient losses must be such that no increase in reactor vessel water temperature will occur. With RPV water temperature remaining below 140°F, adequate margin is being maintained to coolant boiling, evaporative losses are minimal, and refueling floor environmental conditions will not be adversely affected. If temperature is not maintained below this value with only ambient heat losses, decay heat removal capability is required. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems. RHR Shutdown Cooling System requirements in MODE 5, with irradiated fuel in the RPV and with the water level ≥ 22 ft 9 inches above the RPV flange, are given in LCO 3.9.8, "Residual Heat Removal (RHR) – High Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable

(continued)

BASES

ACTIONS (continued)

shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

The required cooling capacity of the alternate method should be sufficient to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Fuel Pool Cooling and Cleanup System, the Reactor Water Cleanup System, the Alternate Decay Heat Removal System (ADHR), or an inoperable but functional RHR shutdown cooling subsystem.

B.1, B.2, and B.3

With the required RHR shutdown cooling subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, additional actions are required to be initiated immediately to minimize any potential fission product release to the environment. This includes ensuring primary containment is OPERABLE and primary containment isolation

(continued)

ACTIONS

B.1, B.2, and B.3 (continued)

capability (i.e., one closed door in each primary containment air lock, and at least one primary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability) in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. In addition, at least one door in each primary containment air lock must be closed. The closed air lock door completes the boundary for control of potential radioactive releases. With the appropriate administrative controls however, the closed door can be opened intermittently for entry and exit. The administrative controls required consist of the stationing of a dedicated individual to assure closure of the door except during the entry and exit, and assuring the door is closed after completion of the containment entry and exit. This allowance is acceptable due to the need for containment access and due to the slow progression of events which may result from inadequate decay heat removal. Loss of decay heat removal would not be expected to result in the immediate release of appreciable fission products to the containment atmosphere. Actions must continue until all requirements of this Condition are satisfied.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation except as permitted by the LCO Note, an alternate method of reactor coolant circulation is required to be established within 1 hour. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of reactor coolant circulation by the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

(continued)

BASES

ACTIONS	C.1 and C.2 (continued) During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR shutdown cooling subsystem), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.
SURVEILLANCE REQUIREMENTS	SR 3.9.9.1 This Surveillance verifies that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	None.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 200°F (normally corresponding to MODE 3) or to allow completing these reactor coolant pressure tests when the initial conditions do not require temperatures > 200°F. Furthermore, the purpose is to allow continued performance of control rod scram time testing required by SR 3.1.4.1 or SR 3.1.4.4 if reactor coolant temperatures exceed 200°F when the control rod scram time testing is initiated in conjunction with an inservice leak or hydrostatic test. These control rod scram time tests would be performed in accordance with LCO 3.10.4, "Single Control Rod Withdrawal - Cold Shutdown," during MODE 4 operation.

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.11, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RCS P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing may eventually be required with minimum

(continued)

BASES

BACKGROUND (continued)	reactor coolant temperatures > 200°F. However, even with required minimum reactor coolant temperatures < 200°F, maintaining RCS temperatures within a small band during this test can be impractical. Removal of heat addition from recirculation pump operation and reactor core decay heat is coarsely controlled by control rod drive hydraulic system flow and reactor water cleanup system non-regenerative heat exchanger operation. Test conditions are focused on maintaining a steady state pressure, and tightly limited temperature control poses an unnecessary burden on the operator and may not be achievable in certain instances. Other testing may be performed in conjunction with the allowances for inservice leak or hydrostatic tests and control rod scram time tests.
APPLICABLE SAFETY ANALYSES	Allowing the reactor to be considered in MODE 4 when the reactor coolant temperature is > 200°F, during, or as a consequence of, hydrostatic or leak testing, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

coolant activity above the limits of LCO 3.4.8, "Reactor Coolant System (RCS) Specific Activity," are minimized. In addition, the primary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated loss of coolant accidents inside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The makeup capability required in MODE 4 by LCO 3.5.2, "Reactor Pressure Vessel (RPV) Water Inventory Control," would be more than adequate to keep the RPV water level above the TAF under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the primary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES (continued)

LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 200°F, can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 200°F, while the ASME inservice test itself requires the safety/relief valves to be gagged, preventing their OPERABILITY. Additionally, even with required minimum reactor coolant temperatures < 200°F, RCS temperatures may drift above 200°F during performance of inservice leak and hydrostatic testing or during subsequent control rod scram time testing, which is typically performed in conjunction with inservice leak and hydrostatic testing. While this Special Operations LCO is provided for inservice leak and hydrostatic testing, and for scram time testing initiated in conjunction with an inservice leak or hydrostatic test, parallel performance of other tests and inspections is not precluded. If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.10, "Residual Heat Removal (RHR) Shutdown Cooling System-Cold Shutdown." The additional requirements for primary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 200°F for the purposes of performing either an inservice leak or hydrostatic test and for control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test.
APPLICABILITY	The MODE 4 requirements may only be modified for the performance of, or as a consequence of, inservice leak or hydrostatic tests, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 200°F. The additional requirement for primary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

(continued)

BASES (continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the

(continued)

BASES

ACTIONS (continued)

LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements shall be entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4. This Required Action includes reducing the average reactor coolant temperature to ≤ 200°F.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operations LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the average reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to ≤ 200°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 for reaching MODE 4 from MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

(continued)

BASES (continued)

REFERENCES	1.	American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.
	2.	USAR, Section 15.6.5.

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown-Initiates a reactor scram; bypasses main steam line isolation, reactor high water level scrams; and reactor low water level EOP bypass control switches become active (i.e., the EOP switches can BYPASS the level 3 trip if taken to the 'BYPASS' position);

b. Refuel-Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation and reactor high water level scrams;.

c. Startup/Hot Standby-Selects NMS scram function for low neutron flux level operation (intermediate range monitors and average power range monitors); bypasses main steam line isolation and reactor high water level scrams; and

d. Run-Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The interlock functions of the shutdown and refuel positions of the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, or startup/hot standby) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod -Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal-Cold Shutdown," and LCO 3.10.8, "SDM Test-Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled by a second licensed operator or other technically qualified member of the unit technical staff. In MODES 3, 4, and 5 with the reactor mode switch in

(continued)

BASES

LCO (continued)	shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5 with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place. In MODE 5, with the reactor mode switch in the refuel position, only one control rod can be withdrawn under the refuel position one rod out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.
APPLICABILITY	Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed without this allowance. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

(continued)

BASES (continued)

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control rods remain inserted and result in operation in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.2.1 and SR 3.10.2.2 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 7.2.1.1. 2. USAR, Section 15.4.1.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal — Hot Shutdown

BASES

BACKGROUND	The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.
APPLICABLE SAFETY ANALYSES	With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of an accident. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions. Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod, including recoupling. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn. To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. The control rods can be made incapable of withdrawal by disarming the control rod either hydraulically or electrically. A control rod can

(continued)

BASES

LCO (continued)	be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rod can be disarmed by disconnecting power from the four directional control valve solenoids. Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.
APPLICABILITY	Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal-Cold Shutdown," and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the refuel position one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication"), full insertion requirements for all other control rods, and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative control in Item d.2 of this Special Operations LCO, minimizes potential reactivity excursions.
ACTIONS	A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

BASES

ACTIONS (continued)

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. This Required Action has been modified by a Note that clarifies the intent of any other LCO's Required Action to fully insert all insertable control rods. This Required Action includes exiting this Special Operations LCO's Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for a required LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternative Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to fully insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued) LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.4.1.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal – Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of an accident. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing the CRD because this removal renders the withdrawn control rod incapable of being scrammed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod, including recoupling.

The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO

(continued)

BASES

LCO (continued)

requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (Item c.2). The control rods can be made incapable of withdrawal by disarming the control rod either hydraulically or electrically. A control rod can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rod can be disarmed by disconnecting power from the four directional control valve solenoids. This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the refuel position one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, minimizes potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial

(continued)

BASES

ACTIONS (continued)

entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action to fully insert all insertable control rods. This Required Action includes exiting this Special Operations LCO's Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for a required LCO.

Required Actions A.2.1 and A.2.2 are alternative Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to fully insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

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

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must immediately be suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most

(continued)

BASES (continued)

ACTIONS

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

expeditious action be taken to either initiate action to restore the CRD and fully insert its control rod, or restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.4.2 is required to preclude the possibility of criticality. SR 3.10.4.3 verifies that all the other control rods other than the control rod being withdrawn are fully inserted. Also SR 3.10.4.4 verifies that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. USAR, Section 15.4.1.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal – Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY – Refueling").

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BASES (continued)

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of an accident. Explicit safety analyses in the USAR (Ref. 1) demonstrate that the proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable refuel position one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks, fail to prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are disarmed. This alternate backup protection is required when removing the CRD because this removal renders the withdrawn control rod incapable of being inserted.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES (continued)

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs – LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 – not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented and this Special Operations LCO applied.

By requiring all other control rods to be fully inserted and a control rod withdrawal block initiated, the function of the inoperable refuel position one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are disarmed adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. The control rods can be made incapable of withdrawal by disarming the control rod either hydraulically or electrically. A control rod can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rod can be disarmed by disconnecting power from the four directional control valve solenoids.

Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduces the potential for reactivity excursions.

(continued)

BASES (continued)

ACTIONS

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

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions commences activities which will restore operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods fully inserted) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

SR 3.10.5.1 verifies that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted. This is required to ensure the SDM is within limits. SR 3.10.5.2 verifies that the local five by five array of control rods, other than the control rod withdrawn for the removal of the associated CRD, is disarmed, while the scram function for the withdrawn rod is not available. This is required to preclude the possibility of criticality. SR 3.10.5.3 verifies that a control rod withdrawal block has been inserted. This ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Also, SR 3.10.5.5 verifies that no other CORE ALTERATIONS are being made. This is required to ensure the assumptions of the safety analysis are satisfied.

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5 (continued) With the exception of SR 3.10.5.4, the Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.4.1.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal — Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rod may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full in" position indicators.

APPLICABLE SAFETY ANALYSES

Explicit safety analyses in the USAR (Ref. 1) demonstrate that the proper operation of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from

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BASES

APPLICABLE SAFETY ANALYSES (continued)	the core cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY-Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated core cells. Prior to entering this LCO, any fuel remaining in a core cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. When loading fuel into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Spiral reloading encompasses reloading a cell (four fuel locations immediately adjacent to a control rod) on the edge of a continuous fueled region (the cell can be loaded in any sequence). Otherwise, all control rods must be fully inserted before loading fuel.

(continued)

BASES (continued)

APPLICABILITY	Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5 is appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.
ACTIONS	<u>A.1, A.2, A.3.1, and A.3.2</u> If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions commences activities which will restore operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner.
SURVEILLANCE REQUIREMENTS	<u>SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3</u> Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. USAR, Section 15.4.1.1.

B 3.10 Special Operations

B 3.10.7 Control Rod Testing—Operating

BASES

BACKGROUND	The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod pattern controller (RPC) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Control Rod Pattern," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RPC. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a control rod drop accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests may include SDM demonstrations, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exceptions to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.
APPLICABLE SAFETY ANALYSES	The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1 and 2. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RPC provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analyses of References 1 and 2 may not be preserved. Therefore, special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence remain valid. When deviating from the prescribed sequences of LCO 3.1.6, individual control rods must be bypassed in the Rod Action Control System (RACS). Assurance that the test sequence is followed can be provided by a second licensed operator or other qualified member of the technical staff verifying conformance to the approved test sequence. These controls are consistent with those normally applied to operation in the startup range as defined in SR 3.3.2.1.9, when it is necessary to deviate from the prescribed sequence (e.g., an inoperable control rod that must be fully inserted).
APPLICABILITY	Control rod testing, with THERMAL POWER greater than 19.0% RATED THERMAL POWER, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 19.0% RATED THERMAL POWER, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed control rod sequences of LCO 3.1.6. While in

(continued)

BASES

APPLICABILITY (continued)	MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal – Hot Shutdown" or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal – Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 1 and 2 are satisfied. During these Special Operations and while in MODE 5, the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock) and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY – Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, minimize potential reactivity excursions.
ACTIONS	A.1 With the requirements of the LCO not met (e.g., the control rod pattern not in compliance with the special test sequence), the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken either to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.
SURVEILLANCE REQUIREMENTS	SR 3.10.7.1 During performance of the special test, a second licensed operator or other qualified member of the technical staff is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. This Surveillance provides adequate assurance that the specified test sequence is being followed and is also supplemented by SR 3.3.2.1.9, which requires verification of the bypassing of control rods in RACS and subsequent movement of these control rods.

(continued)

BASES (continued)

REFERENCES

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR II" (latest approved revision).
2. Letter from T. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test – Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movement within the reactor pressure vessel or control rod replacement. The demonstration must be performed once within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup/hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup/hot standby position while in MODE 5, is provided by the Intermediate Range Monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

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BASES

APPLICABLE SAFETY ANALYSES (continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the Rod Pattern Controller (RPC), APRM, and control rod coupling, the single notch withdrawal mode is specified for out of sequence withdrawals. Requiring the single notch withdrawal mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Final Policy Statement on Technical Specification Improvements (58 FR 39132) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2a and 2d) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RPC (LCO 3.3.2.1, Function 1b, MODE 2), or

(continued)

BASES

LCO (continued)

must be verified by a second licensed operator or other qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in LCO 3.1.6, "Control Rod Pattern" (i.e., out of sequence control rod withdrawals) must be made in the single notch withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1 and A.2

If a control rod is discovered to be uncoupled during this Special Operation, a controlled insertion of the uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since if the control rod fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rod is fully inserted within 3 hours and disarmed (electrically or

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Actions A.1 and A.2 are modified by a Note that allows control rods to be bypassed in the Rod Action Control System (RACS) if required to allow insertion and disarming of the inoperable control rods and continued operation. SR 3.3.2.1.9 provides additional requirements when the control rods are bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1, SR 3.10.8.2 and SR 3.10.8.3

The other LCOs made applicable in this Special Operations LCO are required to have applicable Surveillances met to establish that this Special Operations LCO is being met. However, the control rod withdrawal sequences during the SDM tests may be enforced by the RPC (LCO 3.3.2.1, Function 1b, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RPC (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity, since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" notch position or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. Until the control rod reaches the "full out" position where coupling can be verified, the nuclear instrumentation is observed for any indicated response during withdrawal. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

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BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.10.8.6 CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. A minimum scram accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 1520 psig is well below the expected pressure of 1750 psig. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, GESTAR II" (latest approved revision). 2. Letter, T.A. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," August 15, 1986.

B 3.10 SPECIAL OPERATIONS

B 3.10.9 Suppression Pool Makeup – MODE 3 Upper Containment Pool Drain-Down

BASES

BACKGROUND	Maintaining the SPMU inventory in the upper containment pools until MODE 4 delays completion of outage work in a timely manner. The purpose of the Special Operations LCO is to allow the upper containment pool to be drained below its normal level in MODE 3 such that certain activities can proceed prior to reaching MODE 4. These activities include installation of the gate between the reactor well and the steam dryer storage pool, and completely draining the reactor well.
APPLICABLE SAFETY ANALYSIS	Supporting analyses and engineering calculations determined the required water inventory to ensure that the suppression pool makeup function is satisfied if the specified conditions of this Special Operations LCO are met (Reference 2). Supporting analyses differ from those for TS 3.6.2.2 and TS 3.6.2.4 in that a portion of the SPMU volume is assumed to have been transferred to the suppression pool with the remainder available from the steam separator storage pool portion of the upper containment pool. Complete draining of the reactor well will eliminate all of the SPMU system volume in the upper containment pool except for the water volume in the steam separator storage pool below the top of the weir wall that separates the steam separator storage pool from the reactor well. Accordingly, additional hold-up volumes in the reactor well, reactor well drain lines, and a small portion at the top of the steam dryer storage and fuel transfer pools, are considered, which are offset by increases in initial upper containment pool and suppression pool levels prior to reactor well drain-down in MODE 3. The event analyses demonstrate that the containment spray function of RHR is not required following a design basis loss of coolant accident (LOCA) to protect the containment given the reduced temperature and pressure stipulated by the LCO. The analysis results demonstrate that the containment pressure increase following a design basis LOCA in MODE 3 will not be sufficient to result in the auto-initiation of containment spray. However, operators are permitted to take action to manually actuate containment sprays, if warranted, to mitigate containment overpressure and control offsite/control room dose. In addition to the design basis analyses, drywell bypass capability analyses (Reference 2) indicate that containment pressure exceeds the containment spray auto-initiation setpoint. Steam bypass leakage and the associated capability analyses are discussed in Reference 2.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

For the most limiting break bypass leakage capability analysis, the containment pressure design basis limit is not exceeded. For the design basis accident (DBA) LOCAs and the steam bypass events, the SPMU system design basis function to maintain post-accident drywell vent coverage is ensured by consideration of all potential post-accident entrapment volumes identified in the design-basis. In addition to the design-basis entrapment volumes, the reactor well, reactor well drain lines, a small portion of the steam dryer storage and IFTS pools are included as potential entrapment volumes for the collection of containment spray when the reactor well is drained in MODE 3.

The containment loads evaluation performed for this special operation including the elevated suppression pool water level demonstrates that at the decay time and reactor pressure specified by the LCO, the containment loads are bounded by those calculated for the DBA LOCA.

Specific analyses and evaluations demonstrated containment temperature and pressure as well as radiological consequences are bounded by those following large and small break LOCAs at full power conditions. The applicable analyses and evaluations supporting the low pressure LCO in MODE 3 are contained in References 1, 2, and 3. During these events, the SPMU system is relied upon to dump the steam separator storage pool water to maintain at least 2 feet of drywell horizontal vent coverage and to provide an adequate suppression pool heat sink volume to ensure that the primary containment internal pressure and temperature stay within design limits.

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional, and therefore, no criteria of NRC Policy Statement apply. However, when draining the upper containment pool while in MODE 3, the ACTIONS of the Special Operations LCO shall be met. However, when draining the upper containment pool while in MODE 3, the ACTIONS of the Special Operations LCO shall be met. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying the requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with Special Operations LCO is optional. Operations with the upper containment pool levels below those specified in SR 3.6.2.4.1 can be achieved by exiting the condition where LCO 3.6.2.4 applies. Operation with elevated suppression pool levels is also optional as operation at levels above those specified in LCO 3.6.2.2 can be achieved by exiting the condition where the LCO applies. When draining the upper containment pool while in MODE 3, the ACTIONS of the Special Operations LCO shall be met.

(continued)

BASES

LCO (continued)

Compliance with the Figure 3.10.9-1 level requirements ensures that there is sufficient overlap with the requirements of LCO 3.6.2.2 and 3.6.2.4 such that the combined water volume in containment during the transition to a drained reactor well fulfills the containment water inventory requirements assumed in the analysis. Once the level of the weir wall separating the reactor well from the steam separator storage pool is reached, Figure 3.10.9-1 only applies to the reactor well.

Maintaining the water level in the steam dryer storage pool and in the fuel transfer pool ensures that containment spray water hold-up inside containment is minimized consistent with the supporting analysis.

The reactor subcritical time, suppression pool average temperature, upper containment pool temperature, and reactor steam dome pressure are assumptions of the supporting analyses.

Gate installation in MODES 1, 2 and 3 will occur at the end of a given operating cycle to facilitate early MODE 3 drain down of the reactor well as the plant is in the process of shutting down for the associated refueling outage. During this time, the blind flange in the inclined fuel transfer system (IFTS) penetration can be removed, as permitted by NOTE 4 in surveillance requirement (SR) 3.6.1.3.4. With the IFTS flange removed at power and the upper pool IFTS gate removed, the potential exists to drain the upper containment pools and reduce the inventory available to the SPMU system. Although installation of the IFTS gate limits potential inventory loss to the IFTS pool, loss of water inventory from the IFTS pool and possibly the steam dryer storage pool during MODE 3 drain-down would create additional undesired entrapment volume(s) in the event containment spray was initiated. Compensatory measures have been identified to reduce any failure potentials below the level of credibility that could influence the supporting MODE 3 drain-down analyses. These compensatory measures include placement of the IFTS carriage in the upper pool, suspension of IFTS activities, and closure of IFTS transfer tube shutoff valve 1F42F002 (Reference 4).

Entry in MODE 4 operation does not require the use of this Special Operations LCO or its ACTIONS.

APPLICABILITY

The MODE 3 requirements stated elsewhere in TS may only be modified by this LCO to allow early drain-down during a reactor cool down for a refueling outage. The requirements of this LCO provide conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

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BASES (continued)

ACTIONS

A NOTE has been provided to modify the ACTIONS related to drain-down of the upper containment pools in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry in the Condition unless specifically stated. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry in the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a NOTE has been provided that allows separate entry for each requirement of the LCO.

A.1

With the requirements of the LCO not met (e.g., upper containment pool level not within limits), the draining of the upper containment pool is to be suspended. Thereby, a worsening of the circumstances will be prevented.

A.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of the Required Action initiates activities, which will restore operation consistent with the Special Operations LCO. The Completion Time is intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner.

B.1

Required Action B.1 is an alternative Required Action that can be taken instead of Required Action A.1 and A.2 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCOs Applicability. The allowed Completion Time allows sufficient time to re-establish compliance with the appropriate Technical Specification.

C.1

If the requirements of this Special Operations LCO or the normal MODE 3 requirements cannot be met within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions and is consistent with the time provided in LCO 3.0.3 for reaching MODE 4 from MODE 3.

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SURVEILLANCE REQUIREMENTS

SR 3.10.9.1 and SR 3.10.9.2

Verification of the suppression pool temperature and steam dome pressure ensures that assumptions of the supporting analyses for this Special Operations LCO are continually met. Therefore, the plant response to an accident while in this Special Operations LCO will remain bounded by the design basis loss of coolant accident.

The Frequency of 12 hours is based on engineering judgement and is considered adequate due to the unlikely event of unknowingly adding heat to the Suppression Pool or increasing reactor pressure.

SR 3.10.9.3

Verification of the required upper containment pool and suppression pool levels to be within limits ensures that the engineering assumptions for the calculations supporting this Special Operations LCO are continually met. These assumptions ensure sufficient inventory is available such that drywell vent submergence and suppression pool heat sink requirements are met.

The Frequency of 12 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

SR 3.10.9.4

Verification of the required steam dryer storage pool and fuel transfer pool levels to be within limits ensures that the engineering assumptions for the calculations supporting this Special Operations LCO are continually met. These assumptions ensure sufficient inventory is available such that drywell vent submergence and suppression pool heat sink requirements are met.

The Frequency of 12 hours is based on engineering judgement and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

SR 3.10.9.5

Verification of IFTS carriage located in the upper pool and that IFTS transfer tube shutoff valve 1F42F002 is closed ensures that the engineering assumptions for the calculations supporting this Special Operations LCO are continually met. These assumptions ensure sufficient inventory is available such that drywell vent submergence and suppression pool heat sink requirements are met.

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BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.9.5 (continued) The Frequency of 12 hours is based on engineering judgement and is considered adequate in view of the relatively large volume of water in the fuel transfer pool and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Numerical Applications Calculation, NAI-1863-002, Rev. 0, “Perry Nuclear Power Plant UCP Gate Installation Calculation” (Perry Calculation G43-009).
2. Numerical Applications Calculation NAI-1863-001, Rev. 0, “Perry Nuclear Power Plant Early Drain Down in MODE 3” (Perry Calculation 2.2.1.10).
3. Numerical Applications Report NAI-1863-003, Rev.0, “Perry Draindown Project – Dose Disposition Language”, retained in Perry Technical Assignment File (TAF) 082015.
4. PRA Applications Analysis/Assessment Sequence No. PRA-PY1-15-003-R00, Rev. 0, “PRA Assessment of License Amendment Request for Drain Down of the Reactor Cavity Pool While in MODE 3”.