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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Hope Creek Generating Station
Renewed Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: **Submittal of Hope Creek Generating Station Technical Specification Bases Changes**

PSEG Nuclear LLC (PSEG) hereby submits a complete updated copy of the Hope Creek Technical Specification Bases (Enclosure 1), which includes changes through March 23, 2022, in accordance with the requirements of Hope Creek Technical Specification 6.15.d.

There are no regulatory commitments contained in this letter.

If there are any questions or if additional information is needed, please contact Mr. Michael Wiwel at 856-339-7907.

Respectfully,

Richard Montgomery
Manager - Licensing

Enclosure 1: Hope Creek Generating Station Technical Specification Bases

cc: Administrator, Region I, NRC
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Enclosure 1

Hope Creek Generating Station Technical Specification Bases

2.1 SAFETY LIMITS

BASES

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is $\geq$ the limit specified in Specification 2.1.2. These MCPR values represent a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which 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 measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. 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 Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. 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 that transition boiling will not occur.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the applicable NRC-approved critical power correlations are not valid for all critical power calculations performed at reduced pressures below 585 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. 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 greater than 4.5 psi. Analyses show that with a bundle flow of 28 x 10^3 lbs/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 greater than 28 x 10^3 lbs/hr. Initial full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. Subsequent critical power tests performed by General Electric Hitachi (GEH) for newer fuel designs acquired data at extended pressures down to 600 psia. These data have been shown in the Reference 2 report to support the critical power correlations established for the fuel designs used at Hope Creek. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 24% of RATED THERMAL POWER for reactor pressure below 585 psig is conservative.

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in the onset of transition boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that the onset of transition boiling would not necessarily 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 Safety Limit 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 a 95% confidence that rods are not susceptible to boiling transition, referred to as $MCPR_{95/95}$.

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.

References:

1. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (The approved revision at the time the reload analyses are performed. The approved revision number shall be identified in the CORE OPERATING LIMITS REPORT.)

2. GE-Hitachi Energy Report NEDC-33928P, SC5-03 Evaluation for Hope Creek Generating Station, September 2020.

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2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure 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 Section III of the ASME Boiler and Pressure Vessel Code 1968 Edition, including Addenda through Winter 1969, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The reactor coolant system is designed to the USAS Nuclear Power Piping Code, Section B31.7 1969 Edition, including Addenda through July 1, 1970 for the reactor recirculation piping, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure, 1250 psig for suction piping and 1500 psig for discharge piping. The pressure Safety Limit is selected to be the lowest transient overpressure allowed by the applicable codes.

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, 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 became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

For operation at low pressure and low flow during STARTUP, the APRM scram setting of 17% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RWM. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 17% neutron flux trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux-Upscale setpoint; i.e., for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Simulated Thermal Power-Upscale setpoint, a time constant of 6 $\pm$ 0.6 seconds is introduced into the flow biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the simulated thermal power setpoint as shown in Table 2.2.1-1. Although it is part of the Hope Creek design configuration and Technical Specifications, the APRM simulated thermal power scram is not credited in any Hope Creek safety licensing analyses.

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown. Discussion of the Two Loop and Single Loop Operation setpoint adjustments is provided in TS Bases 3/4.4.1.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine control valve fast closure and turbine stop valve closure trip are bypassed. For a load rejection or turbine trip under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint has been used in transient analyses dealing with coolant inventory decrease. The scram setting was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIV's are closed automatically from measured parameters such as high steam flow, low reactor water level, high steam tunnel temperature, and the low steam line pressure. The MSIV's closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

6. This item intentionally blank

7. Drywell Pressure-High

High pressure in the drywell could indicate a break in the primary pressure boundary systems or a loss of drywell cooling. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant and the primary containment. The trip setting was selected as low as possible without causing spurious trips.

8. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of approximately 35 gallons of water.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

9. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 5% of valve closure from full open, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst case transient.

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

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection with or without coincident failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by the fast acting solenoid valves and in less than 30 milliseconds after the start of control valve fast closure. This is achieved by the action of the fast acting solenoid valves in rapidly reducing hydraulic trip oil pressure at the main turbine control valve actuator disc dump valves. This loss of pressure is sensed by pressure switches whose contacts form the one-out-of-two-twice logic input to the Reactor Protection System. This trip setting, a slower closure time, and a different valve characteristic from that of the turbine stop valve, combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report.

11. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position provides additional manual reactor trip capability.

12. Manual Scram

The Manual Scram pushbutton switches provide a diverse means for initiating a reactor shutdown (scram) to the automatic protective instrumentation channels and provides manual reactor trip capability.

3/4.0 APPLICABILITY

BASES

Specifications 3.0.1 through 3.0.9 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL CONDITIONS or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met. 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).

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in an OPERATIONAL CONDITION or other specified condition in which the specification no longer applies.

The specified time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered an OPERATIONAL CONDITION in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown CONDITION when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. 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. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits 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 CONDITIONS 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 cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met, the LCO is no longer applicable, or the time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in COLD SHUTDOWN when a shutdown is required during POWER operation. If the plant is in a lower CONDITION of operation when a shutdown is required, the time limit for entering the next lower CONDITION of operation applies.

However, if a lower CONDITION of operation is entered in less time than allowed, the total allowable time to enter COLD SHUTDOWN, or other OPERATIONAL CONDITION, is not reduced. For example, if STARTUP is entered in 2 hours, the time allowed to enter HOT SHUTDOWN is the next 11 hours because the total time to enter HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to enter a lower CONDITION of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into an OPERATIONAL CONDITION or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher CONDITION of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower CONDITION of operation.

The shutdown requirements of Specification 3.0.3 do not apply in CONDITIONS 4 and 5, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 LCO 3.0.4 establishes limitations on changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in an OPERATIONAL CONDITION 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 an OPERATIONAL CONDITION or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered following entry into the OPERATIONAL CONDITION or other specified condition in the Applicability for an unlimited period of time. Compliance with ACTIONS that permit continued operation of the unit for an unlimited period of time in an OPERATIONAL CONDITION 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 OPERATIONAL CONDITION change. Therefore, in such cases, entry into an OPERATIONAL CONDITION 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.

LCO 3.0.4.b allows entry into an OPERATIONAL CONDITION 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 OPERATIONAL CONDITION or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

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

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

LCO 3.0.4.c allows entry into an OPERATIONAL CONDITION or other specified condition in the Applicability with the LCO not met based on an ACTION in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into OPERATIONAL CONDITIONS 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 that 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 OPERATIONAL CONDITION or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in OPERATIONAL CONDITIONS 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 OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4, and OPERATIONAL CONDITION 4 to OPERATIONAL CONDITION 5.

Upon entry into an OPERATIONAL CONDITION 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 4.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 4.0.1 or SR 4.0.4 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.

Specification 3.0.5 establishes the allowances 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 Actions(s)) to allow the performance of testing required to restore and demonstrate:

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

b. The OPERABILITY of the other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the testing required to restore and demonstrate the OPERABILITY of the equipment. This Specification does not provide time to perform any other preventative 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 testing required to restore OPERABILITY of another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of testing required to restore and demonstrate the OPERABILITY 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 3.0.5 is applicable to all Technical Specifications; however, the intent of LCO 3.0.5 is not to supersede more specific guidance contained within any individual specification.

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(d)(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 only applies to snubber support functions that are seismic related. In OPERATIONAL CONDITIONS 4 and 5, snubbers only perform seismic support functions. In OPERATIONAL CONDITIONS 1, 2, and 3, some snubbers also perform non-seismic support functions (e.g., hydrodynamic loads, turbine trip loads, etc.). When LCO 3.0.8 is used, confirm that at least one train (or subsystem) of systems supported by the inoperable snubbers would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads.

For snubbers that are being addressed in accordance with this LCO, a record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic), the implementation of any applicable restrictions, and the associated plant configuration must all be available on a recoverable basis for NRC inspection.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the 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 train of the supported system.

When LCO 3.0.8.a is used, one of the following two means of heat removal must be available:

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

- At least one low pressure makeup path (e.g., low pressure coolant injection (LPCI) or core spray (CS)) 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.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

When LCO 3.0.8.b is used, it must be verified that at least one success path exists, using equipment not associated with the inoperable snubber(s), to provide makeup and core cooling needed to mitigate LOOP accident sequences.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

Specification 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the ACTIONS entered in accordance with LCO 3.0.2. This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs.

This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2, 2001).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

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

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

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

The HPCI and RCIC systems are single train systems for injecting makeup water into the reactor during an accident or transient event. The RCIC system is not a safety system, nor required to operate during a transient; therefore, it is not required to meet the single failure proof criterion. The HPCI system provides backup in case of a RCIC system failure. The ADS and low pressure ECCS coolant injection provide the core cooling function in the event of failure of the HPCI system during an accident. For the purposes of LCO 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and LCO 3.0.9 can be used on these single train systems in a manner similar to multiple train or subsystem systems.

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

<u>Specifications 4.0.1 through 4.0.5</u> establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration, or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

<u>Specification 4.0.1</u> establishes the requirement that Surveillance Requirements must be met during the OPERATIONAL CONDITIONS or other specified conditions in the Applicability for which the requirements of the Limiting Conditions for Operation apply unless otherwise specified in an individual Surveillance Requirement. 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 Specification 4.0.2, constitutes a failure to meet an LCO.

3/4.0 APPLICABILITY

BASES (Con't)

Systems and components are assumed to be OPERABLE when the associated Surveillance Requirements have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when either:

a. The systems or components are known to be inoperable, although still meeting the Surveillance Requirements, 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 facility is in an OPERATIONAL CONDITION or other specified condition for which the requirements of the associated Limiting Condition for Operation do not apply, unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given Surveillance. In this case, the unplanned event may be credited as fulfilling the performance of the Surveillance Requirement. This allowance includes those Surveillances whose performance is normally precluded in a given OPERATIONAL CONDITION or other specified condition.

Surveillances, including Surveillances invoked by 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 Specification 4.0.2 prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with Specification 4.0.2. Post maintenance testing may not be possible in the current OPERATIONAL CONDITION 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 an OPERATIONAL CONDITION 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 TS 4.1.3.2 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 950 psig to perform other necessary testing.

b. High Pressure Coolant Injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month surveillance interval. It is not intended that this provision be used repeatedly to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of Specification 4.0.2 is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable, or an affected variable outside the specified limits, when a Surveillance has not been performed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with TS 4.0.2, and not at the time that the specified frequency was not met.

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with Required Actions or other remedial measures that might preclude performance of the Surveillance.

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

When a Surveillance with a frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering Mode 1 after each fuel loading, or in accordance with 10CFR50 Appendix J, as modified by approved exemptions, etc.) is discovered not to have been performed when specified, SR 4.0.3 allows the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity. SR 4.0.3 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 4.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, tests, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 4.0.3 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 Surveillances is expected to be an infrequent occurrence. Use of the delay period established by SR 4.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance.

This risk impact should be managed through the program in place to implement 10 CFR50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.' This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable, or the variable is considered outside the specified limits, and the Completion Times of the Required Actions for the applicable LCO 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 Completions Times of the Required Actions for the applicable LCO begins 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 4.0.1.

Specification 4.0.4 SR 4.0.4 establishes the requirement that all applicable SRs must be met before entry into an OPERATIONAL CONDITION or other specified condition in the Applicability.

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

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

However, in two certain circumstances, failing to meet an SR will not result in SR 4.0.4 restricting an OPERATIONAL CONDITION change or other specified condition change:

(1) 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 4.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 4.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 4.0.4 restriction to changing OPERATIONAL CONDITIONS or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to OPERATIONAL CONDITION or other specified condition changes.

(2) SR 4.0.4 does not restrict changing OPERATIONAL CONDITIONS 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 4.0.3.

The provisions of SR 4.0.4 shall not prevent entry into OPERATIONAL CONDITIONS or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 4.0.4 shall not prevent changes in OPERATIONAL CONDITIONS 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 OPERATIONAL CONDITION or other specified condition in the Applicability associated with transitioning from OPERATIONAL CONDITION 1 to OPERATIONAL CONDITION 2, OPERATIONAL CONDITION 2 to OPERATIONAL CONDITION 3, OPERATIONAL CONDITION 3 to OPERATIONAL CONDITION 4, and OPERATIONAL CONDITION 4 to OPERATIONAL CONDITION 5.

The precise requirements for performance of SRs are specified. 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 OPERATIONAL CONDITION 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.

DELETED

3/4.1.1 SHUTDOWN MARGIN

SHUTDOWN MARGIN (SDM) requirements are specified to ensure:

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

SDM can be demonstrated by using solely analytical methods or by performing a test. SDM can be measured only by performing a test. A test involves collecting data with the reactor at a specified condition or series of conditions. The primary purpose of a SDM Demonstration is to ensure that SDM is equal to or greater than the SDM Limit for a specific core exposure. The primary purpose of a SDM Measurement is to provide SDM in % delta k/k that can be used for: 1) ensuring that SDM is equal to or greater than the SDM Limit for a range of core exposures, 2) determining the need for additional SDM Measurements during the cycle, 3) providing a benchmark for the core design (design vs. actual SDM), and 4) providing a benchmark for potential future analysis of SDM for such events as control rods incapable of full insertion. This higher level of application requires that a SDM Measurement is determined from testing and not through solely analytical methods. Since a SDM Measurement satisfies the primary purpose of a SDM Demonstration, it can be considered a special type of SDM Demonstration.

All SDM Demonstrations involve some usage of analytical methods. The performance of tests lessens the usage of analytical methods, reduces the uncertainty in the results, and thus requires a smaller SDM Limit needed to show adequate SDM. At one end of the spectrum is a series of local criticals where both SDM and the highest worth control rod are determined by test. Although this technique has the minimum uncertainty and thus has the smallest SDM Limit, it still uses analytical methods to determine the worth of all the other control rods. At the other end of the spectrum is usage of solely analytical methods prior to core verification. This technique has the maximum uncertainty and thus has the largest SDM Limit.

The SDM Limit must be increased if the highest worth control rod is determined solely analytically versus a test using the reactor (requires a series of local criticals). This higher limit accounts for uncertainties in the calculation of the highest worth control rod.

SDM is demonstrated to satisfy a variety of OPCON 5 surveillances at the beginning of each cycle and, if necessary, at any future entry to OPCON 5 during the cycle if the assumptions of the previous SDM Demonstration are no longer valid. In most situations, the SDM Demonstration will be based solely on analytical methods and a test will not be performed. If SDM is demonstrated by using solely analytical methods, then SDM must be adjusted to account for the associated uncertainties (excluding the uncertainties in the calculation of the highest worth control rod which are already accounted for in the higher SDM Limit). Prior to core verification, the SDM Limit must be increased due to the possibility of misloaded fuel assemblies.

SDM is measured before or during the first startup following core alterations (ex. fuel movement, control rod replacement), and, if necessary, at any future time in the cycle if a SDM Measurement indicates that the SDM Limit could be reached at a higher core exposure. SDM may be measured during an in-sequence control rod withdrawal or during local criticals. In either case, the measured SDM must be verified to be adequate prior to continuing plant operation.

SDM must be adjusted to cold, xenon-free conditions since these conditions provide a single reference point and are normally the most limiting conditions. The SDM Limit chosen for this reference point ensures that adequate SDM is maintained for all OPCONs.

With control rods incapable of being fully inserted, the reactivity impacts of these control rods must be accounted for in the determination of SDM. In addition to the loss of the worth of these control rods on a scram, the altered power distribution changes the worths of the remaining control rods. By definition, SDM normally does not address known rods that are incapable of full insertion and thus an increased allowance must be added. This verification may be conducted analytically with the necessary adjustments to account for the control rods plus any associated uncertainties.

Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, SDM Measurements must also account for changes in core reactivity during the remainder of the cycle. If there is a core exposure during the remainder of the cycle at which the core reactivity is greater than the core reactivity as which SDM was measured, then the measured value must be reduced to predict SDM at this future core exposure. Therefore, to obtain the final SDM, the measured value must be reduced by the difference between the calculated maximum core reactivity over the remainder of the cycle and the calculated core reactivity at the core exposure at which SDM was measured. If the measured value satisfies the SDM limit but the final value does not satisfy the limit, then it will be necessary to schedule another SDM Measurement prior to reaching the core exposure at which the predicted SDM is equal to the SDM Limit.

When the core is designed, the target SDM is significantly above the SDM Limit. This conservancy accounts for uncertainties in the calculations and allows for the loading, startup, and operation of the reactor.

During OPCON 5, SDM ensures that the reactor does not reach criticality during core alterations (ex. fuel movement, control rod replacements). An evaluation covering each in-vessel fuel or control rod movement is required to demonstrate that SDM is maintained during these activities. This evaluation can be a step-by-step analysis, a bounding analysis, or a combination of these two methods. A step-by-step analysis checks SDM after each movement of a fuel assembly or control rod. A bounding analysis checks the most reactive configurations in a sequence to show acceptability of the entire sequence. All analyses must account for the associated uncertainties in the analytical methods. Prior to core verification, the SDM Limit must be increased due to the possibility of misloaded fuel assemblies. For fuel movement, spiral offload/reload sequences are inherently acceptable, provided the fuel assemblies are reloaded in the design configuration analyzed for the new cycle. The one-rod-out interlock is used to withdraw control rods one-at-a-time for post-maintenance testing, exercising, or other purposes. By demonstrating SDM, the shorting links do not have to be removed during these individual control rod withdrawals.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of rod patterns. Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% delta k/k change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% delta k/k would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

3/4.1.3 CONTROL RODS

The specifications of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analysis, and (3) limit the potential effects of the rod drop accident. The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

The 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 3.1.3.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring a control rod inoperable. Although not all control rods are required to be operable to satisfy the intended reactivity control requirements, control over the number of inoperable control rods is required.

A control rod is considered stuck if it will not insert 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. 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 are met must be performed immediately. Consistent with STS, HCGS will consider "immediately" to mean "the Required Action should be pursued without delay and in a controlled manner. The separation criteria are not met if: a) the stuck control rod occupies a location adjacent to two "slow" control rods, b) the stuck control rod occupies a location adjacent to one "slow" control rod, and the one "slow" control rod is also adjacent to another "slow" control rod, or c) if the stuck control rod occupies a location adjacent to one "slow" control rod when there is another pair of "slow" control rods adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.3.3, "Control Rod Scram Times." In addition, the associated control rod drive must be disarmed in 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 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 isolated from normal insert and withdraw pressure, yet still maintain cooling water to the CRD.

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. 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.

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. The control rods can be electrically disarmed by disconnecting all four directional control valve solenoids. 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.

CONTROL RODS (Continued)

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 8.5% RTP, the generic banked position withdrawal sequence (BPWS) analysis 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. LCO 3.1.3.1.c is modified by a Note indicating that the Condition is not applicable when > 8.5% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.4. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring. In lieu of restoring compliance with BPWS or restoring the control rods to OPERABLE status, an evaluation of the postulated CRDA may be performed to verify that the maximum incremental rod worth of an assumed dropped control rod would not result in exceeding the CRDA design limit of 280 cal/gm fuel enthalpy and would not result in unacceptable dose consequences due to the number of fuel rods exceeding 170 cal/gm fuel enthalpy as described in the UFSAR. The allowed Completion Time of 8 hours is acceptable, considering the low probability of a CRDA occurring.

In addition to the separation requirements for inoperable control rods, an assumption in the CRDA analysis is that no more than three inoperable control rods are allowed in any one BPWS group. Therefore, with one or more BPWS groups having four or more inoperable control rods, the control rods must be restored to OPERABLE status. LCO 3.1.3.1.d is modified by a Note indicating that the Condition is not applicable when THERMAL POWER is > 8.5% RTP since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.4. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

Control rod insertion capability is demonstrated by surveillance 4.1.3.1.2 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. This ensures the control rod is not stuck and is free to insert on a scram signal. At any time, a control rod is immovable for reasons not associated with the control rod drive mechanism, a determination of that control rod's trippability (Operability) must be made and appropriate actions taken. As an example, if the control rod can be scrammed, but can not be moved due to a RMCS failure, the rod(s) may continue to be considered OPERABLE provided all other related surveillances are current.

Damage within the control rod drive mechanism could be a generic problem, therefore with a withdrawn control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

CONTROL RODS (Continued)

The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

Verifying that the scram time for each control rod to notch position 05 is ≤ 7 seconds (SR 4.1.3.2) provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 4.1.3.3.

The scram times specified in Table 3.1.3.3-1 (in the accompanying LCO) are required to ensure that the scram reactivity assumed in the Design Basis Accident (DBA) and transient analysis is met (Ref. 2). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.3.3-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows up to approximately 7% of the control rods (e.g., 185 x 7% = 13) to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3.1, "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 3.1.3.3-1 is accomplished through measurement of the "dropout" times. To ensure that local scram reactivity rates are maintained within acceptable limits, no more than two of the allowed "slow" control rods may occupy adjacent locations.

Table 3.1.3.3-1 is modified by two Notes which state that 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 4.1.3.2.

This LCO (3.1.3.3) applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3.1). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig 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 ≥ 800 psig ensures that the measured 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 that scram time testing is performed within a reasonable time following a shutdown ≥ 120 days or longer, control rods are required to be tested before exceeding 40% RTP following the shutdown. This Frequency is acceptable considering the additional surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the associated core cell and by work on control rods or the CRD System.

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 the sample tested are determined to be "slow." With more than 7.5% of the sample declared to be "slow" per the criteria in Table 3.1.3.3-1, 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 should be different for each test.

CONTROL RODS (Continued)

Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data may have been previously tested in a sample.

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 the affected control rod is still within acceptable limits. The limits for reactor pressures < 800 psig are established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. Limits for ≥ 800 psig are found in Table 3.1.3.3-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of Table 3.1.3.3-1, Note 2, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times are (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 valve in the piping required for scram.

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

When work that could affect the scram insertion time is performed on a control rod or 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 3.1.3.3-1 with the reactor steam dome pressure ≥ 800 psig. Where work has been performed at high reactor pressure, the requirements of SR 4.1.3.3.c and SR 4.1.3.3.d can be satisfied with one test. For a control rod affected by work performed while shut down, however, a zero pressure and high pressure test may be required. This testing ensures that, prior to withdrawing the control rod for continued operation, the control rod scram performance is acceptable for operating reactor pressure conditions. Alternatively, a control rod scram 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.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed. 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.

CONTROL RODS (Continued)

In OPCON 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 OPCON 3 and 4, control rods are only allowed to be withdrawn under limits imposed by the reactor mode switch being in shutdown and by the control rod block being applied. This provides adequate requirements for control rod scram accumulator OPERABILITY during these conditions. In OPCON 5, withdrawn control rods are required to have OPERABLE accumulators.

The actions of Specification 3.1.3.5 are 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 actions for each affected accumulator. Complying with the Required Actions may allow for continued operation and subsequent affected accumulators governed by subsequent Condition entry and application of associated Required Actions.

With one control rod scram accumulator inoperable and the reactor steam dome pressure ≥ 900 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 3.1.3.3-1. Required Action 3.1.3.5.b is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control scram time was within the limits of Table 3.1.3.3-1 during the last scram time test. Otherwise, the control rod 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 fully inserted and declared inoperable (Required Action 3.1.3.5.a.1.c). The allowed Completion Time of 8 hours is 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.

With two or more control rod scram accumulators inoperable and reactor pressure ≥ 900 psig, adequate pressure must be supplied to the charging water header. With inadequate charging water pressure, the accumulators could become inoperable, resulting in a potential degradation of the scram performance. Therefore, within 20 minutes from discovery of charging water header pressure < 940 psig concurrent with conditions in Action 3.1.3.5.a.2, adequate charging water header pressure must be restored. The allowed Completion Time of 20 minutes is reasonable, to place a CRD pump into service to restore the charging header pressure, if required. This Completion Time is based on 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 3.1.3.3-1. Required Action 3.1.3.5.a.2.b is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control scram time is within the limits of Table 3.1.3.3-1 during the last scram time test. Otherwise, the control rod 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 fully inserted and declared inoperable (Required Action 3.1.3.5.a.2.c). The allowed Completion Time of 1 hour is 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.

With one or more control rod scram accumulators inoperable and the reactor pressure < 900 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor pressure < 900 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 940 psig, concurrent with conditions in Action 3.1.3.5.a.3, all control rods associated with inoperable accumulators must be verified to be fully inserted.

CONTROL RODS (Continued)

Withdrawn control rods with inoperable accumulators may fail to scram under these low pressure conditions. The associated control rods must also be inserted, declared inoperable, and disarmed within 1 hour. The allowed Completion Time of 1 hour is reasonable considering the low probability of DBA or transient occurring during the time that the accumulator is inoperable.

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with loss of the CRD charging pump (Required Actions 3.1.3.5.a.2.a or 3.1.3.5.a.3.a) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in 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 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 Requirement 4.1.3.5 requires that the accumulator pressure be checked in accordance with the Surveillance Frequency Control Program 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. Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur.

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 6 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 8.5% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RWM to be OPERABLE when THERMAL POWER is less than or equal to 8.5% of RATED THERMAL POWER provides adequate control.

The RWM provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4.9 of the FSAR and the techniques of the analysis are presented in Reference 1.

The RBM is designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during high power operation. Two channels are provided. Tripping one of the channels will block erroneous rod withdrawal soon enough to prevent fuel damage. This system backs up the written sequence used by the operator for withdrawal of control rods.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concen- tration of 660 ppm in the reactor core and other piping systems connected to the reactor vessel. To allow for potential leakage and imperfect mixing, this con- centration is increased by 25%. The generic design basis of the standby liquid control system provides a specified cold shutdown boron concentration in the reactor core. The standby liquid control system was typically designed to in-ject the cold shutdown boron concentration in 90 to 120 minutes. The time requirement was selected to override the reactivity insertion rate due to cool down following the xenon poison peak. The pumping rate of 41.2 gpm meets the requirement.

The minimum storage volume of the solution is established to include the generic shutdown requirement and to allow for the portion below the pump suction nozzle that cannot be inserted. An additional allowance in the standby liquid control storage volume is provided to account for storage tank instrument inac-curacy and drift. Even with the maximum specified instrument inaccuracy and drift, the required quantity of sodium pentaborate solution is always available for injection.

A normal quantity of 4640 gallons of sodium pentaborate solution having a 14.0 percent concentration is required to meet the shutdown requirements. The temperature requirement for sodium pentaborate solution and the pump suc-tion piping is necessary to ensure the sodium pentaborate remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume assures that the solution is available for use.

Replacement of the explosive charges in the valves will assure that these valves will not fail because of deterioration of the charges. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

The ATWS Rule (10 CFR 50.62) requires the addition of a new design require-ment to the generic standby liquid control system design basis. Changes to flow rate, solution concentration or boron equivalent to meet the ATWS Rule must not invalidate the original system design basis. Paragraph (c)(4) of 10 CFR 50.62 states that:

> "Each boiling water reactor must have a Standby Liquid Control System (SLCS) with a minimum flow capacity and boron control equivalent in control capacity to 86 gallons per minute of 13 weight percent sodium pentaborate solution (natural boron enrichment)."

The described minimum system parameters (82.4 gpm, 13.6 percent concentration and natural boron equivalent) will ensure an equivalent injection capability that exceeds the ATWS Rule requirement. The stated minimum allowable pumping rate of 82.4 gallons per minute is met through the simultaneous operation of both pumps.

The standby liquid control system will also provide the capability to raise and maintain the long-term post-accident coolant inventory pH levels to 7 or above. This will prevent significant fractions of the dissolved iodine from being converted to elemental iodine and then re-evolving to the containment atmosphere.

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (latest approved version).
2. Letter from R.F. Janecek (BWROG) to R.W. Starostecki (NRC), "BWR Owners Group Revised Reactivity Control System Technical Specifications," BWROG-8754, September 17, 1987.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

The specifications in this section help assure that the fuel can be operated safely and reliably during normal operation. In addition, the limits specified in these specifications help ensure that the fuel does not exceed specified safety and regulatory limits during anticipated operational occurrences and design basis accidents. Specifically, these limits:

1. Ensure that the limits specified in 10CFR50.46 are not exceeded following the postulated design basis loss of coolant accident.

2. Ensure reactor operations remains within licensed, analyzed power/flow limits.

3. Ensure that the MCPR Safety Limit is not violated following any anticipated operational occurrence.

4. Ensure fuel centerline temperatures remain below the melting temperature and peak cladding strain remains below 1% during steady state operation.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) is a measure of the average Linear Heat Generation Rate (LHGR) of all the fuel rods in a fuel assembly at any axial location. The Technical Specification APLHGR is the LHGR of the highest-powered fuel rod assumed in the LOCA analyses divided by an assumed conservatively small local peaking factor. Limits on the APLHGR are specified to ensure that the fuel design limits are not exceeded. The limiting value for the APLHGR limit is specified in the CORE OPERATING LIMITS REPORT. The calculation procedure used to establish the APLHGR is based on a loss-of-coolant accident analysis. The post LOCA peak cladding temperature (PCT) is primarily a function of the APLHGR and is dependent only secondarily on the rod to rod power distribution within an assembly. The analytical models used in evaluating the postulated loss-of-coolant accidents are described in Reference 1. These models are consistent with the requirements of Appendix K to 10CRF50.

For plant operation with single recirculation loop, a lower value for the APLHGR limit is specified in the CORE OPERATING LIMITS REPORT. This lower value accounts for an earlier transition from nucleate boiling which occurs following a loss-of-coolant accident in the single loop operation compared to two loop operation.

3/4.2.2 DELETED

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established $MCPR_{99.9\%}$, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the $MCPR_{99.9\%}$ at any time during the transient assuming instrument trip setting given in Specification 2.2.

$MCPR_{99.9\%}$ 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 occurrence of boiling transition is determined using the approved Critical Power correlations (Reference 1). The $MCPR_{99.9\%}$ is expected to always be greater than the $MCPR_{95/95}$ because the $MCPR_{99.9\%}$ includes uncertainties not factored into the $MCPR_{95/95}$ and the 99.9 percent probability basis associated with the $MCPR_{99.9\%}$ is more conservative than the 95 percent probability at a 95 percent confidence level basis for the $MCPR_{95/95}$.

To assure that $MCPR_{99.9\%}$ is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the $MCPR_{99.9\%}$, the required minimum operating limit MCPR of Specification 3.2.3 is obtained.

The MCPR operating limits derived from the transient analysis 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 with moderate frequency that is postulated in Chapter 15 of the UFSAR.

Flow dependent MCPR limits (MCPR(f)) are determined by steady state methods using a core thermal hydraulic code (Reference 1). MCPR(f) curves are provided based on the maximum credible flow runout transient (i.e., runout of both loops).

The methods described in Reference 1 are used to determine the power dependent MCPR limits (MCPR(p)). 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 limits are bypassed, high and low MCPR(p) operating limits are provided for operation between 24% of RATED THERMAL POWER and the bypass power levels.

3/4.2.4 LINEAR HEAT GENERATION RATE

The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial location. This specification assures that the Linear Heat Generation Rate (LHGR) in any fuel rod is less than the design linear heat generation even if fuel pellet densification is postulated. Limits on 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 normal operation or the anticipated operational occurrences identified in Reference 1.

The analytical methods and assumptions used in evaluating the fuel system design limits are presented in Reference 1. The analytical methods and assumptions used in evaluating AOOs and normal operation that determine the LHGR limits are presented in Reference 1.

LHGR limits are developed as a function of exposure to ensure adherence to fuel design limits during the limiting AOOs. The exposure dependent LHGR limits are reduced by an LHGR multiplier (LHGRFAC) at various operating conditions to ensure that all fuel design criteria are met for normal operation and AOOs. A complete discussion of the analysis code is provided in Reference 2.

Flow-dependent LHGR limits were developed to assure adherence to all fuel thermal-mechanical design bases for the slow recirculation flow runout event. From the bounding overpowers, the limits were derived such that, during these events, the peak power would not exceed fuel thermal-mechanical limits. The flow-dependent LHGR limits are generic and cycle-independent, and are specified in terms of a multiplier, LHGRFAC(f), to be applied to the rated LHGR values.

LINEAR HEAT GENERATION RATE (Continued)

Power-dependent LHGR limits, are substituted to assure adherence to the fuel thermal-mechanical design bases at reduced power conditions. Both incipient centerline melting of the fuel and plastic strain of the cladding are considered in determining the power-dependent LHGR limit although the limiting criterion is generally incipient centerline melting. Appropriate LHGR limits are selected based on generic and plant specific transient analyses. These limits are derived to assure that the peak transient power for any transient is not increased above the fuel design basis values. The power-dependent LHGR limits are specified in terms of a multiplier, LHGRFAC(p), to be applied to the rated LHGR values.

Although the LOCA analyses do not credit any reductions in LHGR or MAPLHGR during two-loop operation, the application of the ARTS based fuel thermal-mechanical design analysis limits (LHGRFAC(p) and LHGRFAC(f)) are required to ensure that off-rated conditions not specifically analyzed will not be limiting. (Reference 3)

For single recirculation loop operation, the LHGRFAC multiplier is limited to a maximum value as given in the CORE OPERATING LIMITS REPORT. This maximum limit 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.

References:

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (latest approved version).

2. NEDO-24154-A, "Qualification of the One-Dimensional Core Transient Model (ODYN) for Boiling Water Reactors," August 1986, and NEDE-24154-P-A, Supplement 1, Volume 4, Revision 1, February 2000.

3. NEDC-33153P, "SAFER/GESTR-LOCA Loss of Coolant Accident Analysis for Hope Creek Generating Station," Revision 1, September 2004.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. The system meets the intent of IEEE-279 for nuclear power plant protection systems. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Surveillance and maintenance outage times have been determined in accordance with Reference 1 (NEDC-30851P, "Technical Specification Improvement Analyses for BWR Reactor Protection System," as approved by the NRC and documented in the SER (letter to T. A. Pickens from A. Thadani dated July 15, 1987)) and NEDC-32410P-A, “Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function.” The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1.

The measurement of response time in accordance with the Surveillance Frequency Control Program provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the safety analyses. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times. The response time testing is performed from the 2-out-of 4 Voter logic module output relays through the RPS contacts. The response time of the APRM and 2-out-of-4 Voter electronics from the LPRM detector inputs to the "coil" in the Voter is entirely determined by the digital processing. The time required for the digital processing remains constant within statistical variations. The time base in the digital equipment is confirmed as part of the channel calibration. In addition, automatic self-test functions compare the independent APRM clocks and will detect any significant changes in frequency. Selected sensor response time testing requirements were eliminated based upon NEDO- 32291, “System Analyses for Elimination of Selected Response Time Testing Requirements,” as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Reactor Protection System Response Times are located in UFSAR Table 7.2-3.

As noted, the SR for the APRM Neutron Flux - Upscale, Setdown channel functional test is not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1, since testing of the OPERATIONAL CONDITION 2 required APRM Function cannot be performed in OPERATIONAL CONDITION 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into OPERATIONAL CONDITION 2 if the frequency is not met per SR 4.0.2. In this event, the SR must be performed within 12 hours after entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

Function 2. Average Power Range Monitor

The APRM channels provide the primary indication of neutron flu x with in the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the Local Power Range Monitors (LPRMs) with in 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. Each APRM also includes an Oscillation Power Range Monitor (OPRM) Upscale Function which monitors small groups of LPRM signals to detect thermal hydraulic instabilities. The system conforms to the requirements of IEEE-603.

The APRM System is divided into four APRM channels and four 2-Out-Of-4 voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one unbypassed APRM will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system.

APRM trip Functions are voted independently in three groups:

Functions 2.a, 2.b, 2.c, and 2.d are voted in one group, OPRM Upscale Function 2.f and 2.d in a second group, and the OPRM Defense In Depth Algorithm (DIDA) and 2.d functions in the third group. Therefore, any Function 2.a, 2.b, 2.c, OR 2.d tri p from any two unbypassed APRM channels will result in a full trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip system logic channel (A1, A2, B1, and B2). Similarly, any Function 2.f OR 2.d trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels. Similarly any DIDA OR Function 2.d trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. For the OPRM Upscale, Function 2.f, LPRMs are assigned to "cells" of 3 or 4 detectors. A minimum of 2 LPRMs are required for a cell to be considered responsive. A minimum of 8 responsive cells are required for an OPRM channel to be considered operable.

2.a. APRM Neutron Flux Upscale (Setdown)

For operation at low power (i.e., OPCON 2), the APRM Neutron Flux-Upscale (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 APRM Neutron Flux-Upscale (Setdown) Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux-Upscale Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux-Upscale (Setdown) Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the APRM Neutron Flux-Upscale (Setdown) Function. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 24% RTP (SL 2.1.1) when operating at low reactor pressure and low core flow.

Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 24% RTP.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 24% RTP.

The Average Power Range Monitor Neutron Flux-Upscale (Setdown) Function must be OPERABLE during OPCON 2 when control rods may be withdrawn since the potential for criticality exists.

In OPCON 1, the APRM Neutron Flux-Upscale Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

2.b. APRM Simulated Thermal Power-Upscale

The APRM Simulated Thermal Power (STP)-Upscale 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 APRM Neutron Flux-Upscale Function Allowable Value.

The APRM STP-Upscale function responds to operational events where TH ERMAL POWER increases slowly. 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 Upscale neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the APRM Fixed Neutron Flux-Upscale Function will provide a scram signal before the APRM STP-Upscale function setpoint is exceeded.

Each APRM channel uses one total drive flow signal representative of total core flow. The total drive flow signal is generated by the flow processing logic, part of the APRM channel, by summing the flow calculated from two flow transmitter signal inputs, one from each of the two recirculation loops. The flow processing logic OPERABILITY is part of the APRM channel OPERABILITY requirements for this function.

2.c. Average Power Range Monitor Neutron Flux-Upscale

The APRM Neutron Flux-Upscale Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure.

2.d. Average Power Range Monitor-Inop

For any APRM channel, any time its mode switch is in any position other than "Operate," an APRM module is unplugged, or the automatic self-test system detects a critical fault with the APRM channel, an Inop trip is sent to all four voter channels. If an APRM channel is inoperable, the voting treats it as though a trip condition exists in that channel.

2.e. 2-Out-Of-4 Voter

The 2-Out-Of-4 Voter function provides the interface between the APRM Functions, including the OPRM Upscale Function, and the final RPS trip system logic. As such, it is required to be OPERABLE in the OPERATIONAL CONDITIONS where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the 2-Out-Of-4 Voter Function needs to be OPERABLE in OPCONS 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, a trip is issued from that voter channel to the associated trip system.

APRM trip Functions are voted independently in three groups, Functions 2.a, 2.b, 2.c, and 2.d are voted in one group , OPRM Upscale Function 2.f and 2.d in a second group, and the OPRM Defense In Depth Algorithm (DIDA) and 2.d functions in the third group. The voter also includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (six total outputs). The voter Function 2.e must be declared inoperable if any of its functionality is inoperable.

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function provides protection from exceeding the fuel Safety Limit (SL) MCPR due to anticipated thermal-hydraulic power oscillations.

Reference 3 describes the Detect and Suppress Solution-Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). Reference 3 also describes the DSS-CD Armed Region and the three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the Period Based Detection Algorithm (PBDA), the Amplitude Based Algorithm (ABA), and the Growth Rate Algorithm (GRA). All four algorithms are implemented in the OPRM Upscale Function, but the safety analysis only takes credit for the CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY is based only on the CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into cells for evaluation by the OPRM algorithms.

DSS-CD OPERABILITY requires at least 8 responsive OPRM cells per channel. The DSS-CD software includes a self-test for the responsive OPRM cells; therefore, no SR is necessary.

The OPRM Upscale Function is required to be OPERABLE when the plant is ≥19% RTP, which is established as a power level that is greater than or equal to 5% below the lower boundary of the Armed Region. This requirement is designed to encompass the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. The OPRM Upscale Function is automatically trip-enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is greater than or equal to 24% RTP corresponding to the MCPR monitoring threshold and reactor recirculation drive flow is less than 70% of rated recirculation drive flow. This region is the OPRM Armed Region. Note (m) allows for entry into the OPRM Armed Region without automatic arming of DSS-CD prior to completely passing through the OPRM Armed Region during both the first startup and the first controlled shutdown following DSS-CD implementation. However, during these periods, the OPRM Upscale Function is OPERABLE and DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the OPRM Armed Region flow boundary.

An OPRM Upscale trip is issued from an OPRM channel when the CDA in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. An OPRM Upscale trip is also issued from the channel if any of the defense-in-depth algorithms (PBDA, ABA, GRA) exceeds its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the SLMCPR is exceeded.

The OPRM Upscale Function is not LSSS SL-related (Reference 3) and Reference 4 confirms that the OPRM Upscale Function settings based on DSS-CD also do not have traditional instrumentation setpoints determined under an instrument setpoint methodology.

TS 3.3.1 Actions

<u>a and b</u>

For APRM functions 2.a, 2.b, 2.c, 2.d, and 2.f, ACTION a. is the only applicable action (ACTION b. is noted as not applicable per Note **). For these functions the four APRM channels produce trips that are voted in both trip systems, with two votes being required to initiate the trip. Three OPERABLE channels are required to meet single failure criteria. If one required APRM channel is INOPERABLE, single failure criteria is not met in both trip systems, therefore placing one trip system in trip does not restore single failure criteria for the function. However, placing the affected APRM channel in trip does restore single failure criteria for the function in both trip systems by inserting one vote for the affected functions in all voters, requiring only a single additional vote to initiate a scram in both trip systems. Therefore, for these functions, Note *** specifies that the channel (not the trip system) be placed in a tripped condition.

If two required APRM channels are INOPERABLE, ACTION a. requires placing both channels in trip, which would initiate the protective action. The provisions of Note * apply and only one channel must be placed in a tripped condition. The second channel must be restored to OPERABLE status within 6 hours or the ACTION required by Table 3.3.1-1 for the affected trip functions shall be taken.

For APRM function 2.e, TS 3.3.1 ACTION a. and b. apply as they would for any other RPS channel.

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 when operating at or above 24% 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 adjustment is not required for OPERABILITY when APRM output indicates a higher reactor power than the heat balance calculated reactor power.

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For Functions 2.a, 2.b and 2.c, the CHANNEL CALIBRATION surveillance requirement is modified by two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the

Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

References

1. NEDC-30851P-A, “Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

2. HCGS UFSAR

3. NEDC-33075P-A, Revision 8, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution-Confirmation Density," November 2013.

4. J. Harrison (GEH) letter to NRC, "NEDC-33075P-A, Detect and Suppress Solution - Confirmation Density (DSS-CD) Analytical Limit (TAC No. MD0277)," October 29, 2008 (ADAMS Accession No. ML083040052).

5. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

6. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," October 1995.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

BACKGROUND

The primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs). 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 secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs) and starts the Filtration, Recirculation and Ventilation System (FRVS). The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation and establishment of vacuum with the FRVS within the assumed time limits ensure that fission products that leak from primary containment following a DBA, or are released outside primary containment, or are released during certain operations when primary containment is not required to be OPERABLE are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment, secondary 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 logics are:

reactor vessel water level,
area ambient and differential temperatures,
main steam line (MSL) flow,
Standby Liquid Control (SLC) System initiation,
condenser vacuum,
main steam line pressure,
high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam line flow,
drywell pressure,
RCIC and HPCI steam line pressure,
RCIC and HPCI turbine exhaust diaphragm pressure,
reactor water cleanup (RWCU) differential flow,
reactor steam dome pressure,
main steam line radiation,
reactor building exhaust radiation, and
refueling floor exhaust high radiation.

Redundant sensor input signals from each parameter are provided for

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

BACKGROUND (continued)

initiation of isolation. In addition, manual isolation of the logics is provided.

The isolation actuation instrumentation has inputs to the trip logic of the isolation functions listed below.

1. Primary Containment Isolation

Most Primary Containment Isolation Functions receive inputs from eight sensors in four channels. These inputs are arranged into four two-out-of-two logic PCIS channels. Each one of the two valves on each penetration is closed by one of the four PCIS logics, arranged so that operation of any three logics isolates all of the associated penetrations.

The exception to this arrangement is the Reactor Building Exhaust Radiation - High Function. For this trip function, three radiation monitoring channels input to four two-out-of-three PCIS initiation logics.

The valve groups actuated by the Primary Containment Isolation Trip Function are listed in the Technical Requirements Manual.

2. Secondary Containment Isolation

The outputs of the logic channels in a trip system are arranged into four two-out-of-two trip system logics for Reactor Vessel Water Level - Low Low, Level 2 and for Drywell Pressure - High. The Reactor Building and Refueling Floor Exhaust Radiation - High trip functions each have three radiation monitoring channels that input to four two-out-of-three initiation logics. Each one of the two valves on each penetration and each FRVS unit is actuated by one of the four trip logics, so that operation of any three logics isolates the secondary containment and provides for the necessary filtration of fission products.

The valve groups actuated by the Secondary Containment Isolation Trip Function are listed in the Technical Requirements Manual.

3. Main Steam Line Isolation

Most MSL Isolation Functions receive inputs from four channels. The outputs from these channels are combined in a 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. The MSL drain line has two isolation valves with one two-out-of-two logic system associated with each valve.

The exceptions to this arrangement are the Main Steam Line Flow - High Function and Main Steam Line Tunnel Temperature - High Function. The Main Steam Line Flow - High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of the four trip strings. Two trip strings make up each trip system and both trip systems

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

BACKGROUND (continued)

must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings are arranged in a one-out-of-two taken twice logic. 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), with each trip system isolating one of the two MSL drain valves.

The Main Steam Tunnel Temperature - High Function receives input from 16 channels. The logic is arranged similar to the Main Steam Line Flow - High Function.

The valve groups actuated by the MSL Isolation Trip Functions are listed in the Technical Requirements Manual.

4. Reactor Water Cleanup System Isolation

The Reactor Vessel Water Level - Low Low, Level 2 Isolation 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. The Differential Flow - High and SLC System Initiation Functions receive input from two channels, with each channel in one trip system using a one-out-of-one logic. The Area Temperature - High Function receives input from twelve temperature monitors, six to each trip system. The Area Ventilation Differential Temperature - High Function receives input from twelve differential temperature monitors, six in each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on each RWCU penetration.

The valve groups actuated by the RWCU Isolation Trip Functions are listed in the Technical Requirements Manual.

5, 6. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation

Most Functions that isolate RCIC and HPCI receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems in each isolation group is connected to one of the two valves on each associated penetration.

The exceptions are the RCIC and HPCI Turbine Exhaust Diaphragm Pressure - High and Steam Supply Line Pressure - Low Functions. These Functions receive inputs from four turbine exhaust diaphragm pressure and four steam supply pressure channels for each system. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two two-out-of-two trip systems. Each trip system isolates one valve per associated penetration.

The valve groups actuated by the RCIC and HPCI System Isolation Trip Functions are listed in the Technical Requirements Manual.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

BACKGROUND (continued)

7. Shutdown Cooling System Isolation

The Reactor Vessel Water Level - Low, Level 3 Function receives input from four reactor vessel water level channels. The outputs from the reactor vessel water level channels are connected to two two-out-of-two trip systems. The Reactor Vessel Pressure - High Function receives input from four channels, with each channel in one trip system using a one-out-of-two trip logic. Each of the two trip systems is connected to one of the two valves on each shutdown cooling penetration.

The valve groups actuated by the Shutdown Cooling System Isolation Trip Functions are listed in the Technical Requirements Manual.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the 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 Bases Sections 3/4.6.3, "Primary Containment Isolation Valves," and 3/4.6.5, "Secondary Containment," for more detail of the safety analyses.

Isolation actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

The OPERABILITY of the isolation actuation instrumentation is dependent on the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.2-1. 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.

Table 3.3.2-1 is modified by Note (a) to indicate that a channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Action must be taken. 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 isolation valves will isolate the penetration flow path(s) when necessary.

Allowable Values are specified for each isolation actuation Function specified in the Table. Operation with a trip setpoint less conservative than its Trip Setpoint, but within its Allowable Value, is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In general, the individual Functions are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 consistent with the Applicability for TS 3.6.1.1, "Primary Containment Integrity." 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.

Primary Containment Isolation

1.a. Reactor Vessel Water Level

Low RPV water level indicates that 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 (Trip Function 1.a.1) and Level 1 (Trip Function 1.a.2) supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Reactor Vessel Water Level - Low Low, Level 2 and Low Low Low, Level 1 Trip Functions associated with isolation are implicitly assumed in the UFSAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level signals are initiated from 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. Two channels of Reactor Vessel Water Level - Low Low, Level 2 and Low Low Low, Level 1 Trip Functions are available and are required to be OPERABLE for each PCIS channel to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by these Functions are listed in the Technical Requirements Manual.

1.b. Drywell Pressure - High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Drywell Pressure - High Function, associated with isolation of the primary containment, is implicitly assumed in the UFSAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure - High Function are available and are required to be OPERABLE for each PCIS channel to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1c. Reactor Building Exhaust Radiation - High

High Reactor Building exhaust 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 Exhaust Radiation - High is detected, valves whose penetrations communicate with the primary containment atmosphere are isolated to limit the release of fission products.

The Exhaust Radiation - High signals are initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building. The system consists of three channels. Four high radiation alarms, one from each channel through Class 1E to Class 1E isolation, are supplied to each channel of the Primary Containment Isolation System (PCIS), where two out of three logic is used to initiate closure of primary containment isolation valves and dampers. Three channels of Reactor Building Exhaust - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

1.d. Manual Initiation

The Manual Initiation push button channels introduce signals into the isolation actuation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific UFSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are four push buttons for the logic, one manual initiation push button per PCIS channel.

Four channels of the Manual Initiation Function are available and are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3, since these are the OPERATIONAL CONDITIONS in which the Isolation Actuation automatic Trip Functions are required to be OPERABLE.

Secondary Containment Isolation

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

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. An isolation of the secondary containment and actuation of the FRVS are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level - Low Low, Level 2 Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation systems on Reactor Vessel Water Level - Low Low, Level 2 support

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

actions to ensure that any offsite releases are within the limits calculated in the safety analysis.

Reactor Vessel Water Level - Low Low, Level 2 signals are initiated from 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. Two channels of Reactor Vessel Water Level - Low Low, Level 2 Function are available and are required to be OPERABLE for each PCIS channel to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low Low, Level 2 Function is required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 where considerable energy exists in the Reactor Coolant System (RCS); thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In OPERATIONAL CONDITIONS 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these OPERATIONAL CONDITIONS; thus, this Function is not required. In addition, the Function is also required to be OPERABLE when handling irradiated fuel in the secondary containment and during CORE ALTERATIONS, because the capability of isolating potential sources of leakage must be provided to ensure that offsite dose limits are not exceeded if core damage occurs.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

2.b Drywell Pressure - High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the FRVS are initiated in order to minimize the potential of an offsite dose release. The isolation on high drywell pressure supports actions to ensure that any offsite releases are within the limits calculated in the safety analysis. High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure - High Functions are available and are required to be OPERABLE for each PCIS channel to ensure that no single instrument failure can preclude performance of the isolation function.

The Drywell Pressure - High Function is required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in OPERATIONAL CONDITIONS 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these OPERATIONAL CONDITIONS.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.c, 2.d. Refueling Floor and Reactor Building Exhaust Radiation - High

High Refueling Floor or Reactor Building exhaust 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 or the refueling floor due to a fuel handling accident. When Exhaust Radiation - High is detected, secondary containment isolation and actuation of the FRVS are initiated to limit the release of fission products as assumed in the UFSAR safety analyses (Ref. 4).

The Exhaust Radiation - High signals are initiated from radiation detectors that are located on the ventilation exhaust ducts coming from the reactor building and the refueling floor zones, respectively. Three channels of Reactor Building Exhaust Radiation - High Function and three channels of Refueling Floor Exhaust Radiation - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Refueling Floor and Reactor Building Exhaust Radiation - High Functions are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 where considerable energy exists; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In OPERATIONAL CONDITIONS 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these OPERATIONAL CONDITIONS; thus, these Functions are not required. In addition, the Functions are also required to be OPERABLE when handling recently irradiated fuel in the secondary containment, because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

2.e. Manual Initiation

The Manual Initiation for secondary containment isolation can be performed by manually initiating a primary containment isolation. There is no specific UFSAR safety analysis that takes credit for this Function. It is retained for the overall redundancy and diversity of the secondary containment isolation instrumentation as required by the NRC approved licensing basis.

There are four push buttons for the logic, one manual initiation push button per PCIS channel. 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 available and are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 and when handling recently irradiated fuel in the secondary containment. These are the OPERATIONAL CONDITIONS and other specified conditions in which

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the Secondary Containment Isolation automatic Functions are required to be OPERABLE.

Main Steam Line Isolation

3.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 MSLs 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 available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3.b. Main Steam Line Radiation - High, High

The Main Steam Line Radiation - High, High Function is provided to detect gross release of fission products from the fuel and to initiate closure of the reactor recirculation water sample line isolation valves. Four detectors, one for each main steam line, monitor the gross gamma radiation. Each detector provides an input to one of the four trip logic channels.

3.c. 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 condition and the RPV cooling down more than 100ºF/hr 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/hr) is not reached.

The MSL low pressure signals are initiated from four transmitters that are connected to the MSL header. Four channels of Main Steam Line Pressure - Low Function are available and are required to be OPERABLE to ensure that no

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

single instrument failure can preclude the isolation function.

The Main Steam Line Pressure - Low Function is only required to be OPERABLE in OPERATIONAL CONDITION 1 since this is when the assumed transient can occur (Ref. 2).

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3.d. 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) (Ref. 1). 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 and offsite doses do not exceed the 10 CFR 50.67 limits.

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. Four channels of Main Steam Line Flow - High Function for each MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3.e. 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 available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

As noted in the footnote Table 3.3.2-1, the channels are not required to be OPERABLE in OPERATIONAL CONDITIONS 2 and 3 when all turbine stop valves (TSVs) are less than 90% open, since the potential for condenser

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

overpressurization is minimized. Switches are provided to manually bypass the channels when all TSVs are closed.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3.f. Main Steam Line Tunnel Temperature - High

The Main Steam Line Tunnel 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 UFSAR, since bounding analyses are performed for large breaks, such as MSLBs.

Area temperature signals are initiated from sensors located in the main steam tunnel. Sixteen channels of Main Steam Tunnel Temperature - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

3.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 UFSAR safety analysis that takes credit for this Function. It is retained for the overall redundancy and diversity of 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.

Four channels of Manual Initiation Function are available and are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3, since these are the OPERATIONAL CONDITIONS in which the MSL isolation automatic Functions are required to be OPERABLE.

Reactor Water Cleanup System Isolation

4.a, 4.b. RWCU 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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

most RWCU operational transients. This Function is not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as MSLBs.

The high differential flow signals are initiated from transmitters that are connected to the inlet (from the reactor vessel) and outlets (to condenser and feedwater) of the RWCU System. Two channels of RWCU Differential Flow - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

4.c, 4.d. RWCU Area Temperature and Area Ventilation Differential Temperature - High

RWCU area temperatures and area ventilation differential temperatures are 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 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 UFSAR, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Area temperature and area ventilation differential temperature signals are initiated from temperature elements that are located in the room that is being monitored. Twelve ambient temperature sensor/monitors provide input to the RWCU Area Temperature - High Function. Twelve channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Twelve differential temperature sensor/monitors provide input to the RWCU Area Ventilation Differential Temperature - High Function. Twelve channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

4.e. 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. SLC System initiation signals are initiated from the two SLC pump start signals.

Two channels (one from each pump) of the SLC System Initiation Function are available and are required to be OPERABLE only in OPERATIONAL CONDITIONS 1 and 2 (when the SLC system is required to be OPERABLE), since these OPERATIONAL CONDITIONS are consistent with the Applicability for the SLC

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

System (TS 3.1.5).

4.f. 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, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on Level 2 supports actions to ensure that the 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 the UFSAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

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 available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

4.g. 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 UFSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two push buttons for the logic, one manual initiation push button per trip system.

Two channels of the Manual Initiation Function are available and are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 since these are the OPERATIONAL CONDITIONS in which the RWCU System Isolation automatic Functions are required to be OPERABLE.

Reactor Core Isolation Cooling and High Pressure Coolant Injection Systems Isolation

5.a, 6.a, 5.b, 6.b. RCIC and HPCI Steam Line Δ Pressure (Flow) - High

Steam Line Δ Pressure (Flow) - High Functions are provided to detect a break of the RCIC or HPCI steam lines and initiate closure of the steam line isolation valves of the appropriate system. If the steam is allowed to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

continue flowing out of the break, the reactor will depressurize and the core can uncover. Therefore, the isolations are initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for these Functions is not assumed in any UFSAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC or HPCI steam line breaks from becoming bounding.

The RCIC and HPCI Steam Line Δ Pressure (Flow) - High signals are initiated from transmitters (two for HPCI and two for RCIC) that are connected to the system steam lines. Two channels of both RCIC and HPCI Steam Line Δ Pressure (Flow) - High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

To eliminate the possibility of spurious system isolations, the RCIC and HPCI systems incorporate a time delay, which will prevent short term flow peaks from initiating a system isolation but will not interfere with the leak detection and isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

5.c, 6.c. RCIC and HPCI Steam Supply Pressure - Low

Low steam supply pressure indicates that the pressure of the steam in the HPCI or RCIC turbine may be too low to continue operation of the associated system’s turbine. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the UFSAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing RCIC and HPCI initiations (Ref. 3).

The RCIC and HPCI Steam Supply Pressure - Low signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both RCIC and HPCI Steam Supply Line Pressure - Low Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

5.d, 6.d. RCIC and HPCI 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’s turbine. That is, one of two exhaust diaphragms has ruptured and pressure is reaching turbine casing pressure limits. These isolations are for equipment protection and are not assumed in any transient or accident analysis in the

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

UFSAR. These instruments are included in the TS because of the potential for risk due to possible failure of the instruments preventing RCIC and HPCI initiations (Ref. 3).

The RCIC and HPCI Turbine Exhaust Diaphragm Pressure - High signals are initiated from transmitters (four for HPCI and four for RCIC) that are connected to the area between the rupture diaphragms on each system's turbine exhaust line. Four channels of both RCIC and HPCI Turbine Exhaust Diaphragm Pressure - High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

5.e, 5.f, 5.g, 5.h, 6.e, 6.f, 6.g. 6.h. RCIC and HPCI Area and Differential Temperature - High

Area ambient and differential 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. These Functions are not assumed in any UFSAR transient or accident analysis, since bounding analyses are performed for large breaks such as recirculation or MSL breaks.

Pump Room Area and Differential Temperature - High signals are initiated from sensor/switches that are appropriately located to protect the system that is being monitored. Two channels for each RCIC and HPCI Pump Room Temperature - High and Pump Room Ventilation Ducts Δ Temperature - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

Ambient temperature sensor/switches detect temperature increases in the steam supply piping areas. Two channels for each RCIC and HPCI Pipe Routing Area Temperature - High Function and six channels for each RCIC and HPCI Torus Compartment Temperature - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

5.i, 6.i. Drywell Pressure - High

High drywell pressure can indicate a break in the RCPB. The RCIC and HPCI 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 and HPCI turbine exhaust by Drywell Pressure - High is indirectly assumed in the UFSAR accident analysis because the turbine exhaust leakage path is not assumed to contribute to offsite doses.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Four channels of both RCIC and HPCI Drywell Pressure - High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

5.j, 6.j. Manual Initiation

The Manual Initiation push button channels introduce signals into the RCIC and HPCI systems' isolation logics that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific UFSAR safety analysis that takes credit for these Functions. They are retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There is one manual initiation push button for each of the HPCI and RCIC systems.

One channel of both RCIC and HPCI Manual Initiation Functions is available and is required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 since these are the OPERATIONAL CONDITIONS in which the RCIC and HPCI systems' Isolation automatic Functions are required to be OPERABLE.

Shutdown Cooling System Isolation

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

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, isolation of 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 safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the recirculation and MSL. 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 caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

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 available and 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 Function is required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 to prevent this potential

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

flow path from lowering the reactor vessel level to the top of the fuel.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

7.b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High

The Reactor Vessel (RHR Cut-in Permissive) Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This interlock 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 UFSAR.

The Reactor Vessel (RHR Cut-in Permissive) Pressure - High signals are initiated from four transmitters. Four channels of Reactor Vessel (RHR Cut-in Permissive) Pressure - High Function are available and are required to be OPERABLE. The Function is only required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3, since these are the only OPERATIONAL CONDITIONS in which the reactor can be pressurized; thus, equipment protection is needed.

The valve groups actuated by this Function are listed in the Technical Requirements Manual.

7.c. Manual Initiation

The Manual Initiation push button channels introduce signals into the RHR shutdown cooling isolation logic that are redundant to the automatic protective instrumentation and provide manual isolation capability. There is no specific UFSAR safety analysis that takes credit for this Function. It is retained for overall redundancy and diversity of the isolation function as required by the NRC in the plant licensing basis.

There are two push buttons for the logic, one manual initiation push button per trip system.

Two channels of the Manual Initiation Function are available and are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3 since these are the OPERATIONAL CONDITIONS in which the RHR System Shutdown Cooling Mode Isolation automatic Functions are required to be OPERABLE.

ACTIONS

3.3.2.b

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 for Functions 1.b, 2.b, 7.a and 7.b and 24 hours for Functions other than Functions 1.b, 2.b, 7.a and 7.b has been shown to be acceptable (Refs. 5 and 6) 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 Action 3.3.2.b.1.b or 3.3.2.b.1.c. Placing the

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

ACTIONS (continued)

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), the Action required by Table 3.3.2-1 must be taken.

If there are no OPERABLE channels for a trip function in one trip system, and the inoperable channels cannot be restored to OPERABLE status within one hour, the inoperable channels must be placed in the tripped condition per Action 3.3.2.b.1.a. Alternately, if it is not desired to place the channels in trip, the Action required by Table 3.3.2-1 must be taken.

Footnote (e) to Table 3.3.2-1 modifies the minimum OPERABLE channels per trip function requirement to state that sensors are arranged per valve group, not per trip system. Where the trip function actuates a single valve group, Action 3.3.2.b applies for all cases in which less than the minimum required number of channels are OPERABLE. For trip functions annotated by footnote (e), Action 3.3.2.b.1.a applies when neither isolation logic (inboard or outboard) meets the minimum OPERABLE channels requirement.

For trip functions 1.c, 2.c and 2.d, a minimum of three OPERABLE channels per trip system are required. For these trip functions, three radiation monitoring channels input to four two-out-of-three PCIS initiation logics. When one RFE-RMS or one RBE-RMS channel is inoperable, Action 3.3.2.b.1.c applies. When more than one RFE-RMS or more than one RBE-RMS channel is inoperable, Action 3.3.2.b.1.a applies because a sufficient number of inputs would not be available to satisfy the actuation logic for any PCIS channel.

SURVEILLANCE REQUIREMENTS

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Surveillance and maintenance outage times have been determined in accordance with References 5 and 6.

When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. Selected sensor response time testing requirements were eliminated based upon Reference 7, NEDO-32291, “System Analyses for Elimination of Selected Response Time Testing Requirements,” as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Isolation System Instrumentation Response Times are located in UFSAR Table 7.3-16.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

REFERENCES

1. UFSAR, Section 6.3.

2. UFSAR, Chapter 15.

3. NEDO-31466, "Technical Specification Screening Criteria Application and Risk Assessment," November 1987.

4. UFSAR, Section 15.7.4.

5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," as approved by the NRC and documented in the SER (letter to S.D. Floyd from C.E. Rossi dated June 18, 1990).

6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," as approved by the NRC and documented in the SER (letter to D.N. Grace from C.E. Rossi dated January 6, 1989).

7. NEDO-32291, “System Analyses for Elimination of Selected Response Time Testing Requirements,” as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994).

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. ECCS actuation instrumentation is eliminated from response time testing requirements based on NEDO-32291, “System Analyses for Elimination of Selected Response Time Testing Requirements,” as approved by the NRC and documented in the SER (letter to R.A. Pinelli from Bruce A. Boger, dated December 28, 1994). The Emergency Core Cooling System Response Times are located in UFSAR Table 7.3-17.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. .Surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2. The safety evaluation reports documenting NRC approval of NEDC-30936P-A are contained in letters to D. N. Grace from A. C. Thadani (Part 1) and C. E. Rossi (Part 2) dated December 9, 1988. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971, NEDO-24222, dated December 1979, and Section 15.8 of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a position switch for each of two turbine stop valves provides input to one EOC-RPT system; a position switch from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 24% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 175 ms. Included in this time are: the response time of the sensor, the time allotted for breaker arc suppression (135 ms @ 100% RTP), and the response time of the system logic.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. .Surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (With Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2 and GENE-770-06-2-A. "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications." The safety evaluation reports documenting NRC approval of NEDC-30936P-A and GENE-770-06-2-A are contained in letters to D. N. Grace from A. C. Thadani dated December 9, 1988 (Part 1), D. N. Grace to C. E. Rossi dated December 9, 1988 (Part 2), and G. J. Beck from C. E. Rossi dated September 13, 1991.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits and Section 3/4.3 Instrumentation. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block.

No safety analysis or safety credit is taken for the APRM initiated rod blocks, they are provided to reduce the risk of exceeding RPS trip setpoints. HCGS is choosing to maintain the functions in Technical Specifications for administrative reasons (versus relocating to a licensee controlled document). The APRM Upscale (Setdown) rod block is based on a Simulated Thermal Power (STP) signal. To develop an APRM Simulated Thermal Power signal, the APRM neutron flux signal, which is derived by averaging the LPRM input signals, has a low-pass filter with a six second time constant applied to the APRM neutron flux signal. The design function of the rod block is to prevent operators from inadvertently reaching the APRM Upscale (Setdown) trip. The use of a STP signal is only applicable to the APRM Upscale (Setdown) rod block, and not to the APRM Upscale (Setdown) RPS trip which is solely based on the APRM neutron flux signal.

The Rod Block Monitor (RBM) Setpoints are credited in the safety analysis. The UFSAR Chapter 15 Rod Withdrawal Error (RWE) at power event analysis performed for each fuel cycle takes credit for RBM generated rod blocks. The results of the RWE at power event analysis are considered in establishing the cycle specific operating limits for the fuel. The TS include the following RBM setpoints: Low Trip Setpoint (LTSP), Intermediate Trip Setpoint (ITSP), and High Trip Setpoint (HTSP); Low Power Setpoint (LPSP), Intermediate Power Setpoint (IPSP), and High Power Setpoint (HPSP); and Downscale Trip Setpoint (DTSP). The values of the trip setpoints (LTSP, ITSP, and HTSP) are dependent on the fuel cycle specific RWE at power MCPR analysis results and are provided in the CORE OPERATING LIMITS REPORT (COLR). The power setpoints (LPSP, IPSP, and HPSP) define the lower bounds of the range in which the corresponding LTSP, ITSP, and HTSP are applicable. The ranges of applicability based on allowable values for the LPSP, IPSP, and HPSP are defined in notes b, c, and d of Table 3.3.6-2 Control Rod Block Instrumentation Setpoints. The values of the LPSP, IPSP, and HPSP power setpoints do not change on a cycle-by-cycle basis. Therefore, the values of these power setpoints are included in the TS. The value of the DTSP is provided in the COLR; however, the DTSP is not credited in the RWE analysis. RBM operability is required based on Rated Thermal Power in conjunction with MCPR criteria. When the MCPR is greater than or equal to the value specified in the COLR for the applicable Rated Thermal Power, the necessary margin to safety analysis acceptance criteria is maintained for full withdrawal of any control rod and the RBM function is not required.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is an allowance for instrument drift specifically allocated for each trip in the safety analyses. Discussion of the Two Loop and Single Loop Operation setpoint adjustments is provided in TS Bases 3/4.4.1. Discussion of the Two Loop and Single Loop Operation setpoint adjustments is provided in TS Bases 3/4.4.1

For the Rod Block Monitor Upscale (Function 1.a), the CHANNEL CALIBRATION surveillance requirement is modified by two Notes (per TSTF-493). The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as-left setting for the channel be within the as-left tolerance of the Trip Setpoint. The as-left and as-found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as-left channel setting cannot be returned to a setting within the as-left tolerance of the Trip Setpoint, then the channel shall be declared inoperable. The as-left tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy and the measurement and test equipment error (including readability). The as-found tolerance for this function is calculated using the square-root-sum-of-squares of the reference accuracy, instrument drift, and the measurement and test equipment error (including readability).

As noted, the SR for the Reactor Mode Switch Shutdown Position functional test 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 OPERATIONAL CONDITIONS 3 and 4 if the frequency is not met per SR 4.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels, and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with 10 CFR Part 50, Appendix A, General Design Criteria 19, 41, 60, 61, 63 and 64.

3/4.3.7.2 DELETED

3/4.3.7.3 DELETED

3/4.3.7.4 REMOTE SHUTDOWN SYSTEM

The OPERABILITY of the remote shutdown system ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criteria 19 of 10 CFR 50.

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," December 1980 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

3/4.3.7.6 SOURCE RANGE MONITORS

The source range monitors provide the operator with information of the status of the neutron level in the core at very low power levels during startup and shutdown. At these power levels, reactivity additions shall not be made without this flux level information available to the operator. For a discussion of SPIRAL RELOAD and SPIRAL UNLOAD and the associated flux monitoring requirements, see Technical Specification Bases Section 3/4.9.2. When the intermediate range monitors are on scale, adequate information is available without the SRMs and they can be retracted.

3/4.3.7.7 DELETED

MONITORING INSTRUMENTATION (Continued)

3/4.3.7.8

The material originally contained in Section 3/4.3.7.8 was deleted with the issuance of the Full Power license. However, to maintain numerical continuity between the succeeding sections and existing station procedural references to those Technical Specifications Sections 3/4.3.7.8 has been intentionally left blank.

3/4.3.7.9 LOOSE-PART DETECTION SYSTEM

THIS SECTION DELETED

3/4.3.7.10 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

Deleted

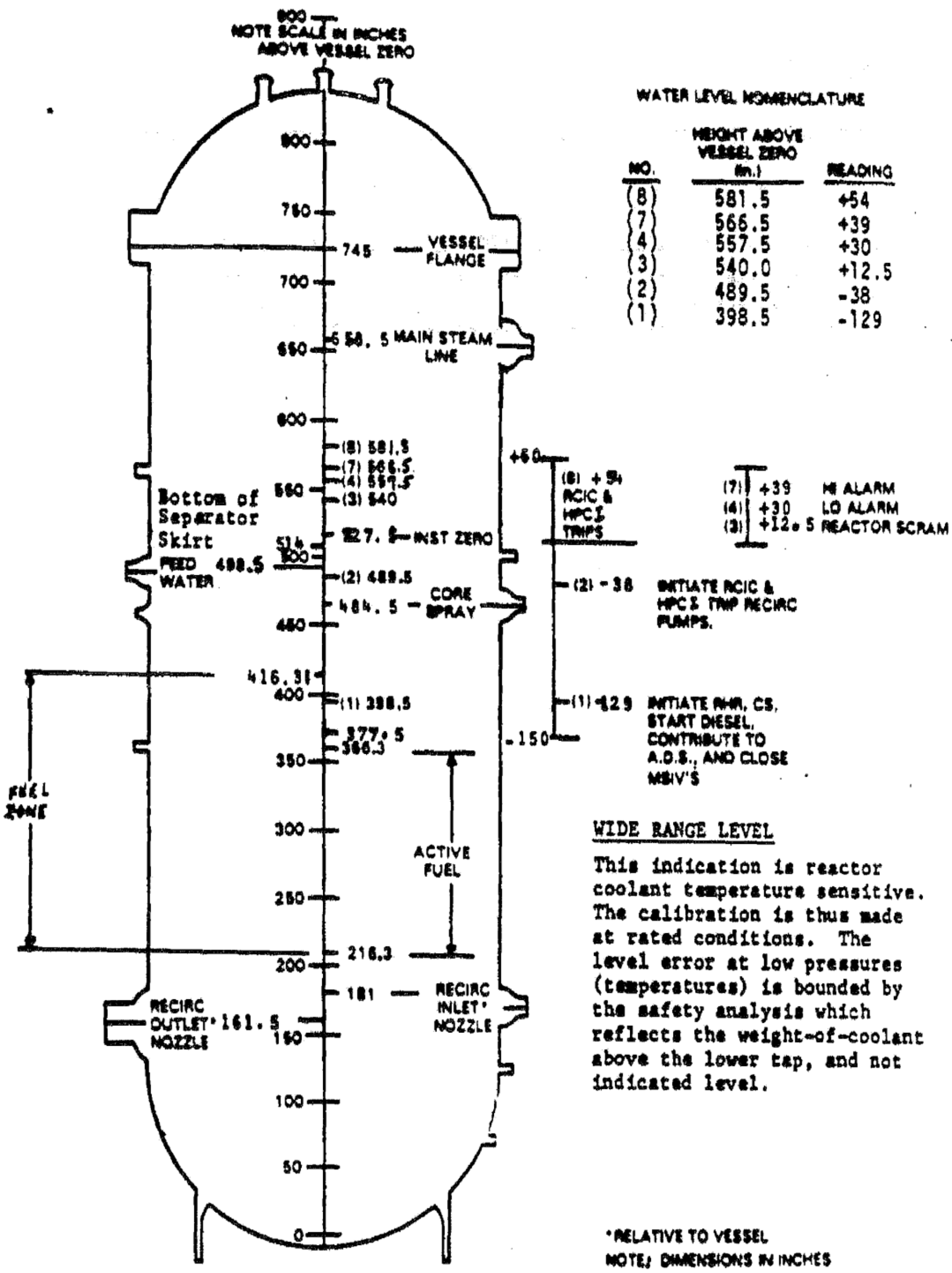
3/4.3.7.11 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

Deleted

3/4.3.8 DELETED

3/4.3.9 FEEDWATER/MAIN TURBINE TRIP SYSTEM ACTUATION INSTRUMENTATION

The feedwater/main turbine trip system actuation instrumentation is provided to initiate action of the feedwater system/main turbine trip system in the event of a high reactor vessel water level (Level 8) to mitigate potential damage to the main turbine.



WATER LEVEL NOMENCLATURE

NO.	HEIGHT ABOVE VESSEL ZERO (in.)	READING
(8)	581.5	+54
(7)	566.5	+39
(4)	557.5	+30
(3)	540.0	+12.5
(2)	489.5	-38
(1)	398.5	-129

WIDE RANGE LEVEL

This indication is reactor coolant temperature sensitive. The calibration is thus made at rated conditions. The level error at low pressures (temperatures) is bounded by the safety analysis which reflects the weight-of-coolant above the lower tap, and not indicated level.

Bases Figure B 3/4 3-1

REACTOR VESSEL WATER LEVEL

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION

BACKGROUND

The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the main condenser mechanical vacuum pump breaker following events in which main steam line radiation exceeds predetermined values. Tripping the mechanical vacuum pump limits the offsite and control room doses in the event of a control rod drop accident (CRDA). The trip logic consists of two independent channels of the Main Steam Line Radiation - High, High function. A trip of either channel is sufficient to result in a pump trip signal for both mechanical vacuum pumps.

APPLICABLE SAFETY ANALYSES

The Mechanical Vacuum Pump Trip Instrumentation is assumed in the safety analysis for the CRDA. The Mechanical Vacuum Pump Trip Instrumentation initiates a trip of the mechanical vacuum pump to limit offsite and control room doses resulting from fuel cladding failure in a CRDA (Ref. 1).

The mechanical vacuum pump trip instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the mechanical vacuum pump trip is dependent on the OPERABILITY of the individual Main Steam Line Radiation - High, High instrumentation channels, which must have their setpoints within the specified Allowable Value of Surveillance Requirement 4.3.10.c. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the mechanical vacuum pump breakers.

APPLICABILITY

The mechanical vacuum pump trip is required to be OPERABLE in OPERATIONAL CONDITIONS 1 and 2 when any mechanical vacuum pump is in service (i.e., taking a suction on the main condenser) and any main steam line not isolated, to mitigate the consequences of a postulated CRDA. In this condition fission products released during a CRDA could be discharged directly to the environment. Therefore, the mechanical trip is necessary to assure conformance with the radiological evaluation of the CRDA. In OPERATIONAL CONDITION 3, 4 or 5 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. When the mechanical vacuum pump is not in service or the main steam lines are isolated, fission product releases via this pathway would not occur.

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION (continued)

ACTION a.

With one channel inoperable, but with mechanical vacuum pump trip capability maintained (refer to ACTION b Bases), the mechanical vacuum pump trip instrumentation is capable of performing the intended function. However, the reliability and redundancy of the mechanical vacuum pump trip instrumentation is reduced, such that a single failure in the remaining channel could result in the inability of the mechanical vacuum pump trip instrumentation to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive numbers of inoperabilities affecting multiple channels, and the low probability of an event requiring the initiation of mechanical vacuum pump trip, 12 hours has been shown to be acceptable (Ref. 2) to permit restoration of an inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status, the plant must be brought to an OPERATIONAL CONDITION or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours. Alternately, the associated mechanical vacuum pump(s) may be removed from service since this performs the intended function of the instrumentation. An additional option is provided to isolate the main steam lines which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

The allowed completion time of 12 hours is reasonable, based on operating experience, to reach OPERATIONAL CONDITION 3 from full power conditions, or to remove the mechanical vacuum pump(s) from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

ACTION b.

ACTION b. is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels result in not maintaining mechanical vacuum pump trip capability. The mechanical vacuum pump trip capability is maintained when one channel is OPERABLE such that the Mechanical Vacuum Pump Trip Instrumentation will generate a trip signal from a valid Main Steam Line Radiation - High, High signal, and the mechanical vacuum pump breakers will open. This would require one channel to be OPERABLE, and the mechanical vacuum pump breakers to be OPERABLE. With mechanical vacuum pump trip capability not maintained, the plant must be brought to an OPERATIONAL CONDITION or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours. Alternately, the associated mechanical vacuum pump(s) may be removed from service since this performs the intended function of the instrumentation. An additional option is provided to isolate the main steam lines which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser.

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION (continued)

The allowed completion time of 12 hours is reasonable, based on operating experience, to reach OPERATIONAL CONDITION 3 from full power conditions, or to remove the mechanical vacuum pump(s) from service, or to isolate the main steam lines, in an orderly manner and without challenging plant systems.

ACTION c.

ACTION c. allows that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated ACTIONs may be delayed for up to 6 hours provided mechanical vacuum pump trip capability is maintained. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the required ACTIONs taken. This allowance 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 mechanical vacuum pump will trip when necessary.

Surveillance Requirement 4.3.10.a

Performance of the CHANNEL CHECK in accordance with the Surveillance Frequency Control Program 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 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.

Surveillance Requirement 4.3.10.b

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

3/4.3.10 MECHANICAL VACUUM PUMP TRIP INSTRUMENTATION (continued)

Surveillance Requirement 4.3.10.c

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. For the purpose of this surveillance, normal background is the dose level experienced at 100% rated thermal power with hydrogen water chemistry at the maximum injection rate. The trip setpoint for the Main Steam Line Radiation - High, High trip function and requirements for setpoint adjustment are specified in Technical Specification 3.3.2.

Surveillance Requirement 4.3.10.d

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

REFERENCES

1. UFSAR, Section 15.4.9.5.1.2

2. NEDC-30851P-A, Supplement 2, "Technical Specification Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989

3/4.3.11 DELETED

3/4.3.12 RPV WATER INVENTORY CONTROL INSTRUMENTATION

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 2.1.4 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 OPERATIONAL CONDITIONS 1, 2, and 3 in TABLE 3.3.2-2, "ISOLATION ACTUATION INSTRUMENTATION SETPOINTS."

With the unit in OPERATIONAL CONDITION 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 OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 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.

The purpose of the RPV Water Inventory Control Instrumentation is to support the requirements of LCO 3.5.2, "RPV Water Inventory Control (WIC)," and the definition of DRAIN TIME. There are functions that support automatic isolation of Residual Heat Removal (RHR) subsystem and Reactor Water Cleanup (RWCU) system penetration flow path(s) on low RPV water level.

A double-ended guillotine break of the Reactor Coolant System (RCS) is not considered in OPERATIONAL CONDITIONS 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

3/4.3.12 RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

engineering judgment, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure 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 below on a Function-by-Function basis.

1.a, 2.a. Deleted

1.b, 2.b. Deleted

3/4.3.12 RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

1.c, 2.c Deleted

3.a. RHR System Shutdown Cooling Mode Isolation – 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 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. The Reactor Vessel Water Level - Low, Level 3 Function associated with RHR System isolation may be credited for automatic isolation of penetration flow paths associated with the RHR System.

Reactor Vessel Water Level - Low, Level 3 signals are initiated from four level transmitters (two per valve) 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 valve) of the Reactor Vessel Water Level - Low, Level 3 Function are available, only two channels (all in the same valve group) are required to be OPERABLE.

The Reactor Vessel Water Level - Low, Level 3 Allowable Value was chosen to be the same as the Primary Containment Isolation Instrumentation Reactor Vessel Water Level - Low, Level 3 Allowable Value (TABLE 3.3.2-2), since the capability to cool the fuel may be threatened.

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.

4.a. Reactor Water Cleanup System Isolation – 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 valves that will close automatically without offsite power RPV water level prior to the RPV water level being equal to the TAF when actuated by RPV water level isolation instrumentation. 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.

Reactor Vessel Water Level - Low Low, Level 2 is initiated from two channels per valve group 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 valve group) of the Reactor Vessel Water Level - Low Low, Level 2 Function are available, only two channels (all in the same valve group) are required to be OPERABLE.

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.

3/4.3.12 RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

ACTIONS

ACTION a. directs taking the appropriate ACTION referenced in Table 3.3.12-1. The applicable ACTION referenced in the Table is Function dependent.

TABLE 3.3.12-1 ACTION 83 Deleted

TABLE 3.3.12-1 ACTION 84 Deleted

TABLE 3.3.12-1 ACTION 85

RHR System Shutdown Cooling Mode Isolation, Reactor Vessel Water Level – Low, Level 3, and Reactor Water Cleanup System Isolation, 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. Immediate action is to place the channel in trip. With the inoperable channel in the tripped condition, the remaining channel will isolate the penetration flowpath on low water level. If both channels are OPERABLE and placed in trip, the penetration flowpath will be isolated. Alternately, ACTION 85 requires the associated penetration flowpaths to be immediately declared incapable of automatic isolation and directs initiating action to calculate DRAIN TIME. The calculation cannot credit automatic isolation of the affected penetration flow paths.

SURVEILLANCE REQUIREMENTS

4.3.12 states that each RPV WIC actuation instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL FUNCTIONAL TEST at the frequencies shown in Table 4.3.12-1.

3/4.3.12 RPV WATER INVENTORY CONTROL (WIC) INSTRUMENTATION (Continued)

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.

3/4.4.1 RECIRCULATION SYSTEM

The impact of single recirculation loop operation upon plant safety is assessed and shows that single loop operation is permitted if the APRM scram and control rod block setpoints are adjusted as noted in Tables 2.2.1-1 and 3.3.6-2 respectively. APLHGR limits are decreased by the factor given in the CORE OPERATING LIMITS REPORT (COLR), LHGR limits are decreased by the factor given in the COLR, and MCPR operating limits are adjusted as specified in the COLR.

The Average Power Range Monitor Scram and rod block functions vary as a function of recirculation loop drive flow (w). The effective drive flow correction term (Δw) is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop operation (TLO) and single loop operation (SLO) at the same core flow. Δw is based on a physical phenomenon and represents the amount of drive flow from the active loop that flows backwards through the inactive loop's jet pumps during SLO. The flow input to the APRM STP Scram function Allowable Value (AV) and Nominal Trip Set Point (NTSP) is adjusted by Δw during SLO to account for this phenomenon.

The form of the function equation is: Slope x (Flow [w] - Flow Offset [Δw]) + Power Offset.

GEH's setpoint methodology is described in NEDC-33864P Appendix P, P1 and P2 (VTD 432598). The methodology also accounts for increased uncertainty in the idle recirculation loop flow signal, which requires the NTSP to be further from the AV under SLO than it is under TLO. This is accomplished by reducing the power offset term for the APRM STP-Upscale RPS Trip (Table 2.2.1-1 Function 2.b):

TLO AV: $0.56w + 60\%$
TLO NTSP: $0.56w + 58\%$

SLO AV: $0.56(w - \Delta w) + 60\%$
SLO NTSP: $0.56(w - \Delta w) + 57\%$

When the SLO mode is manually enabled the NUMAC APRM instrument applies an offset term to the flow signal. To avoid an additional action to manually adjust the power offset (from 58% to 57 %), the SLO NTSP equation is solved for the same power offset as the TLO NTSP equation. Using $\Delta w = 9\%$ yields a flow offset of 10.8% to maintain the power offset at 58%:

$$0.56(w - 9\%) + 57\% \approx 0.56(w - 10.8\%) + 58\%$$

This 10.8% flow offset term is defined as the "SLO Setting Adjustment" (the actual value is 10.79 but it is rounded up to one decimal place for conservatism since the SLO Setting Adjustment is programmed to one decimal place in the NUMAC equipment). This term is applied to the NTSP during SLO by the NUMAC APRM to both account for the 9% Δw flow offset and the increased margin required to the AV. The Δw and SLO Setting Adjustment values have been inserted into the APRM STP-Upscale equations in Table 2.2.1-1.

This same methodology is also applied to the APRM STP-Upscale Rod Block Trip (Table 3.3.6-2 Function 2.a).

Use of the SLO Setting Adjustment simplifies the process for adjusting APRM scram and control rod block setpoints for SLO, as required by TS 3/4.4.1. Expressing the SLO Trip Setpoint in terms of SLO Setting Adjustment reflects how the NUMAC PRNM system is setup and operated.

Additionally, surveillance on the pump speed of the operating recirculation loop is imposed to exclude the possibility of excessive core internals vibration. The surveillance on differential temperatures below 38% THERMAL POWER or 50% rated recirculation loop flow is to mitigate the undue thermal stress on vessel nozzles, recirculation pump and vessel bottom head during the extended operation of the single recirculation loop mode.

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 facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation.

Recirculation loop flow mismatch limits are in compliance with the ECCS LOCA analysis design criteria for two recirculation loop operation. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA. In the case where the mismatch limits cannot be maintained during two loop operation, continued operation is permitted in a single recirculation loop mode.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Sudden equalization of a temperature difference > 145°F between the reactor vessel bottom head coolant and the coolant in the upper region of the reactor vessel by increasing core flow rate would cause undue stress in the reactor vessel bottom head.

ACTION 2 and 3

The APRM system is divided into four APRM channels and four 2-Out-Of-4 voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two voters, with each group of two voters providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels (trip systems), to be bypassed (also refer to TS 3.3.1 Bases).

The ACTIONS maintain the requirement to reduce the APRM scram and control rod block setpoints and allowable values within four hours of entering single loop operation (SLO). Failure to lower the setpoints requires declaring the APRM channel(s) inoperable and entering the applicable LCO for scram and control rod block instrumentation and taking the actions required by the referenced specifications (TS 3.3.1 and TS 3.3.6).

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1375 psig in accordance with the ASME Code. A total of 13 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case transient.

The original safety/relief valves (SRVs) at Hope Creek were the Target Rock 2-Stage SRVs. Target Rock 3-Stage SRVs have been evaluated and approved for installation at Hope Creek. The following paragraph is only applicable to Hope Creek's 2-Stage SRVs

Demonstration of the safety relief valve lift settings occurs only during shutdown. The safety relief valve pilot stage assemblies are set pressure tested in accordance with the recommendations of General Electric SIL No. 196, Supplement 14 (April 23, 1984), "Target Rock 2-Stage SRV Set- Point Drift." Set pressure tests of the safety relief valve main (mechanical) stage are conducted in accordance with the Surveillance Frequency Control Program.

General Electric SIL No. 196, Supplement 14 is not applicable to the Target Rock 3-Stage SRVs. Target Rock 3-Stage SRVs are set pressure tested in accordance with the requirements of the ASME OM Code as described in the Hope Creek IST Program Plan.

The low-low set system ensures that safety/relief valve discharges are minimized for a second opening of these valves, following any overpressure transient. This is achieved by automatically lowering the closing setpoint of two valves and lowering the opening setpoint of two valves following the initial opening. In this way, the frequency and magnitude of the containment blowdown duty cycle is substantially reduced. Sufficient redundancy is provided for the low-low set system such that failure of any one valve to open or close at its reduced setpoint does not violate the design basis.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These detection systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems", May 1973 and Generic Letter 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping."

Proceduralized, manual quantitative monitoring and calculation of leakage rates, found by the NRC staff, in GL 88-01, Supp. 1, to be an acceptable alternative during repair periods of up to 30 days, should be demonstrated to have accuracy comparable to the installed drywell floor and equipment drain sump monitoring system.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

The limit placed upon the rate of increase in UNIDENTIFIED LEAKAGE meets the guidance of Generic Letter 88-01, "NRC Position on IGSCC in BWR Austinitic Stainless Steel Piping."

3/4.4.4 This section has been deleted.

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the maximum two-hour total effective dose equivalent (TEDE) resulting from a main steam line failure outside the containment during steady state operation is well within the 10 CFR 50.67 limits as modified in Regulatory Guide 1.183, Table 6. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as site boundary location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131, but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Monitoring the iodine activity in the primary coolant and taking responsible actions to maintain it at a reasonably low level will aid in ensuring the accumulated time of plant operation with high iodine activity will not exceed 800 hours in a consecutive 12-month period. The results of all primary coolant specific activity analyses which exceed the limits of Specification 3.4.5 will be documented pursuant to Specification 6.9.1.5.

Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analysis following power changes may be permissible if justified by the data obtained.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment. The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable OPERATIONAL CONDITION(S) while relying on the ACTIONS.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section (3.9) of the UFSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation. Specifically the average rate of change of reactor coolant temperature during normal heatup and cooldown shall not exceed 100˚F during any 1-hours period.

The operating limit curves specified in the PTLR are derived from the fracture toughness requirements of 10 CFR 50 Appendix G and ASME Code Section XI, Appendix G. The curves are based on the RT_{NDT} and stress intensity factor information for the reactor vessel components. Fracture toughness limits and the basis for compliance are more fully discussed in UFSAR Chapter 5, paragraph 5.3.1.5, “Fracture Toughness.” Tabulated values for the P-T curves are specified in the PTLR.

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of some of these tests are specified in the PTLR. Reactor operation and resultant fast neutron, E greater than 1 MeV, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, nickel content and copper content of the material in question, can be predicted using the PTLR and the recommendations of Regulatory Guide 1.99, Rev. 2, “Radiation Embrittlement of Reactor Vessel Material”. The pressure/temperature limit curves, specified in the PTLR, includes an assumed shift in RT_{NDT} for the end of life fluence.

The fluence was determined using the NRC-approved RAMA Fluence Methodology. This methodology is consistent with the guidance in Regulatory Guide 1.190, Rev.0 “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

The actual shift in RT_{NDT} of the vessel material will be established periodically during operation by removing and evaluating, irradiated flux wires installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the flux wires and vessel inside radius are essentially identical, the irradiated flux wires can be used with confidence in predicting reactor vessel material transition temperature shift. The operating limit curves specified in the PTLR shall be adjusted as required, on the basis of the flux wire data and recommendations of Regulatory Guide 1.99, Rev 2.

PRESSURE/TEMPERATURE LIMITS (Continued)

The pressure-temperature limit lines shown in the PTLR, curves for inservice leak and hydrostatic testing and reactor criticality have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing.

The number of reactor vessel irradiation surveillance capsules and the frequencies for removing and testing the specimens in these capsules are provided in UFSAR Section 5.3 and Appendix 5A.

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment, however, single failure considerations require that two valves be OPERABLE. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks. The minimum closure time is consistent with the assumptions in the safety analyses to prevent pressure surges.

3/4.4.8 DELETED

3/4.4.9 RESIDUAL HEAT REMOVAL

A single shutdown cooling mode loop provides sufficient heat removal capability for removing core decay heat and mixing to assure accurate temperature indication, however, single failure considerations require that two loops be OPERABLE or that alternate methods capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation.

3/4.5.1 ECCS - OPERATING

The core spray system (CSS), together with the LPCI mode of the RHR system, is provided to assure that the core is adequately cooled following a loss-of-coolant accident and provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The CSS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the CSS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. Four subsystems, each with one pump, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

The surveillance requirements provide adequate assurance that the LPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

Verification days that each RHR System cross tie valve on the discharge side of the RHR pumps is closed and power to its operator, if any, is disconnected ensures that each LPCI subsystem remains independent and a failure in the flow path in one subsystem will not affect the flow path of the other LPCI subsystem. Acceptable methods of removing power to the operator include de-energizing breaker control power or racking out or removing the breaker. For the valves in high radiation areas, verification may consist of verifying that no work activity was performed in the area of the valve since the last verification was performed. If one of the RHR System cross tie valves is open or power has not been removed from the valve operator, both associated LPCI subsystems must be considered inoperable. These valves are under strict administrative controls that will ensure that the valves continue to remain closed with either control or motive power removed.

3/4.5.1 ECCS - OPERATING (Continued)

The high pressure coolant injection (HPCI) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which CSS operation or LPCI mode of the RHR system operation maintains core cooling.

The capacity of the system is selected to provide the required core cooling. The HPCI pump is designed to deliver greater than or equal to 5600 gpm at reactor pressures between 1120 and 200 psig. Initially, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem . There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allow entry into an OPERATIONAL CONDITION 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.

ECCS - OPERATING (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CSS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system. If any one LPCI subsystem or one CSS subsystem is inoperable in addition to an inoperable HPCI system, the inoperable LPCI subsystem/CSS subsystem or the HPCI system must be restored to OPERABLE status within 72 hours. In this condition, adequate core cooling is ensured by the OPERABILITY of the automatic depressurization system (ADS) and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in reduced ECCS capability to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI system or the LPCI/CSS subsystem to OPERABLE status.

If the HPCI system is inoperable along with both a LPCI subsystem and a CSS subsystem being inoperable, the overall ECCS reliability to address a design basis LOCA is significantly reduced. The limited availability of ECCS subsystems requires a more restrictive allowed outage time of 8 hours to restore either the HPCI system or the LPCI or CSS subsystems to OPERABLE status due to the overall reduction in defense in depth of the ECCS to fulfill its safety function to respond to an accident condition. The 8 hour completion time takes into account the additional redundancy afforded by the four independent loop design of the Hope Creek LPCI system to still provide a low pressure injection source into the reactor to maintain core cooling and the low likelihood of experiencing a LOCA during the 8 hour completion time.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor to be in HOT SHUTDOWN with vessel pressure not less than 200 psig. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety-relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves although the safety analysis only takes credit for four valves. It is therefore appropriate to permit one valve to be out-of-service for up to 14 days without materially reducing system reliability.

3/4 5.2 – REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL

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 2.1.4 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 Analysis:

With the unit in OPERATIONAL CONDITION 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 OPERATIONAL CONDITIONS 4 and 5 to protect Safety Limit 2.1.4 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 OPERATIONAL CONDITIONS 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 judgement, that while in OPERATIONAL CONDITIONS 4 and 5, one low pressure ECCS injection/spray subsystem can 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).

Limiting Condition for Operation:

The RPV water level must be controlled in OPERATIONAL CONDITIONS 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 2.1.4.

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 2.1.4 and can be managed as part of normal plant operation.

RPV WATER INVENTORY CONTROL (Continued)

One low pressure ECCS injection/spray subsystem is required to be OPERABLE and capable of being manually aligned and started 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. A low pressure ECCS injection/spray subsystem consists of either one Core Spray System (CSS) subsystem or one Low Pressure Coolant Injection (LPCI) subsystem. Each CSS subsystem consists of two motor driven pumps, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV. Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV.

The LCO is modified by a note which allows a required LPCI subsystem 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 OPERATIONAL CONDITIONS 4 and 5. Requirements on water inventory control are contained in LCO 3.3.12, RPV WATER INVENTORY CONTROL INSTRUMENTATION, and LCO 3.5.2, RPV WATER INVENTORY CONTROL. RPV water inventory control is required to protect Safety Limit 2.1.4 which is applicable whenever irradiated fuel is in the reactor vessel.

Actions:

Action a. – If the required low pressure 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 allowed outage time for restoring the required low pressure 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 4 hours, 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.

RPV WATER INVENTORY CONTROL (Continued)

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.

Action b. - Deleted

Action c. - 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 secondary containment provides a controlled volume in which fission products can be contained, diluted, and processed prior to release to the environment. Verification that the secondary containment boundary is capable of being established in less than the DRAIN TIME is required. The required verification confirms actions to establish the secondary containment boundary are preplanned and necessary materials are available. The secondary containment boundary is considered established when one Filtration, Recirculation and Ventilation (FRVS) ventilation unit is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

Verification that secondary 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. Secondary containment penetration flow paths form a part of the secondary containment boundary. Verification of the capability to isolate each secondary containment penetration flow path in less than the DRAIN TIME is required. The required verification confirms actions to isolate secondary 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 secondary 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.

One FRVS ventilation unit is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Verification of the capability to place one FRVS ventilation unit in operation in less than the DRAIN TIME is required. The required verification confirms actions to place a FRVS ventilation unit in operation are preplanned and necessary materials are available. Verification that a FRVS ventilation unit can be placed in operation must be performed within 4 hours. The required verification is an administrative activity and does not require manipulation or testing of equipment.

If any of the above Action c conditions are not met, immediate actions must be initiated to restore DRAIN TIME to 36 hours or greater.

RPV WATER INVENTORY CONTROL (Continued)

Action d. - With the DRAIN TIME less than 8 hours, mitigating actions are implemented in case an unexpected draining event should occur.

Immediate action to establish an additional method of water injection augmenting the ECCS injection/spray subsystem required by the LCO is required. 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 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.

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 secondary containment provides a control volume into which fission products can be contained, diluted, and processed prior to release to the environment. Actions to immediately establish the secondary containment boundary are required. With secondary containment boundary established, one FRVS ventilation unit is capable of maintaining a negative pressure in the secondary containment with respect to the environment.

The secondary containment penetrations form a part of the secondary containment boundary. Actions to immediately verify that each secondary containment penetration flow path is isolated or to verify that it can be manually isolated from the control room are required.

One FRVS ventilation unit is capable of maintaining the secondary containment at a negative pressure with respect to the environment and filter gaseous releases. Actions to immediately verify that at least one FRVS ventilation unit is capable of being placed in operation are required. The required verification is an administrative activity and does not require manipulation or testing of equipment.

If any of the above Action d conditions are not met, immediate actions must be initiated to restore DRAIN TIME to 36 hours or greater.

Action e. - 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.

RPV WATER INVENTORY CONTROL (Continued)

Surveillance Requirements:

Surveillance Requirement (SR) 4.5.2.1 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 2.1.4 and can be managed as part of normal plant operation.

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, the 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, NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," or commitments to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

RPV WATER INVENTORY CONTROL (Continued)

TS 4.0.1 requires SRs to be met between performances. Therefore, any changes in plant conditions that would change the DRAIN TIME require that a new DRAIN TIME be determined.

SRs 4.5.2.2 and 4.5.2.3 - The minimum water level of 5 inches required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the Core Spray System (CSS) subsystem or LPCI subsystem pumps, 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.

The required CSS is OPERABLE if it can take suction from the CST, and the CST water level is sufficient to provide the required NPSH for the CSS pumps. Therefore, a verification that either the suppression pool water level is greater than or equal to 5 inches or that a CSS subsystem is aligned to take suction from the CST and the CST contains greater than or equal to 135,000 available gallons of water, ensures that the CSS subsystem can supply the required makeup water to the RPV.

SR 4.5.2.4 - 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.

SR 4.5.2.5 - Deleted

SR 4.5.2.6 - 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.

SR 4.5.2.7 - 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.

RPV WATER INVENTORY CONTROL (Continued)

SR 4.5.2.8 - This surveillance verifies that a CSS subsystem or LPCI subsystem can be manually aligned and started, including any necessary valve alignment, instrumentation, or controls, to transfer water from the suppression pool or CST to the RPV. 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.

The Surveillance Frequencies in the above SRs are controlled under the Surveillance Frequency Controlled 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.

6. General Electric Service Information Letter No. 388, "RHR Valve Misalignment During Shutdown Cooling Operation for BWR 3/4/5/6," February 1983.

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CSS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITIONS 1, 2 or 3 is also required by Specification 3.6.2.1.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR 50.67 during accident conditions.

In high radiation areas and in areas posted as neutron exposure areas and controlled in a manner similar to high radiation areas, use of administrative means to verify position of valves and blind flanges is acceptable for Surveillance Requirement 4.6.1.1.b since access to these areas is typically restricted in accordance with the requirements of Technical Specification 6.12 and/or plant procedures. Therefore, the probability of misalignment of these components, once they have been verified to be in the proper position, is low.

Use of administrative means to verify position of valves and blind flanges that are locked, sealed or otherwise secured is acceptable for Surveillance Requirement 4.6.1.1.b. 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 of these components, once they have been verified to be in the proper position, is low.

3/4.6.1.2 PRIMARY CONTAINMENT LEAKAGE

The limitations on primary containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the design basis LOCA maximum peak containment accident pressure of 50.6 psig, P_a. As an added conservatism, the measured overall integrated leakage rate (Type A test) is further limited to less than or equal to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the Primary containment Leakage Rate Testing Program.

3/4.6.1.3 PRIMARY CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the primary containment air locks are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the Primary Containment Leakage Rate Testing Program. Only one closed door in each air lock is required to maintain the integrity of the containment.

3/4.6.1.4 (Deleted)

3/4.6.1.5 PRIMARY CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 50.6 psig in the event of a LOCA. A visual inspection in accordance with the Primary Containment Leakage Rate Testing Program is sufficient.

3/4.6.1.6 DRYWELL AND SUPPRESSION CHAMBER INTERNAL PRESSURE

The limitations on drywell and suppression chamber internal pressure ensure that the containment peak pressure of 50.6 psig does not exceed the design pressure of 62 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 3 psid. The limit of -0.5 to +1.5 psig for initial positive containment pressure will limit the total pressure to 50.6 psig which is less than the design pressure and is consistent with the safety analysis.

3/4.6.1.7 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 340°F during LOCA conditions and is consistent with the safety analysis. The 135°F average temperature is conducive to normal and long term operation.

3/4.6.1.8 DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

The 500 hours/365 days limit for the operation of the purge valves and the 6" nitrogen supply valve during plant Operational Conditions 1, 2 and 3 is intended to reduce the probability of a LOCA occurrence during the above operational conditions when the applicable combination of the above valves are open.

Blow-out panels are installed in the CPCS ductwork to provide additional assurance that the FRVs will be capable of performing its safety function subsequent to a LOCA.

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM (Continued)

The use of the drywell and suppression chamber purge exhaust lines for pressure control during plant Operational Conditions 1, 2 and 3 is unrestricted provided 1) only the inboard purge exhaust isolation valves on these lines and the vent valves on the 2-inch vent paths are used and 2) the outboard purge exhaust isolation valves remain closed. This is because in such a situation, the vent valves will sufficiently choke the flow and additionally the applicable valves will close in a timely manner during a LOCA or steam line break accident and therefore the control room and the site boundary dose guidelines of applicable 10 CFR dose limits will not be exceeded in the event of an accident. The design of the purge supply and exhaust isolation valves and the 6-inch nitrogen supply valve meets the requirements of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations".

The 0.60 L_a leakage limit shall not be exceeded when the leakage rates determined by the leakage integrity tests of these valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

3/4.6.2. DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 62 psig during primary system blowdown from full operating pressure.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from 1020 psig. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss of coolant accident, the pressure of the liquid must not exceed 62 psig, the suppression chamber maximum internal design pressure. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant to be considered is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, containment pressure during the design basis accident is approximately 50.6 psig which is below the design pressure of 62 psig. Maximum water volume of 122,000 ft^3 results in a downcomer submergence of 3.33 ft and the minimum volume of 118,000 ft^3 results in a submergence of approximately 3.0 ft. The majority of the Bodega tests were run with a submerged length of four feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown

DEPRESSURIZATION SYSTEMS (Continued)
tested during the Humboldt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

Should it be necessary to make the suppression chamber inoperable, this shall only be done as specified in Specification 3.5.3.

The Hope Creek design contains a bypass line around each of the RHR heat exchangers. The line contains a valve that is used for adjusting flow through the heat exchanger. The valve is not designed to be a tight shut-off valve. With the bypass valve closed, a portion of the total flow travels through the bypass line, which can affect overall heat transfer, although no heat transfer performance requirement of the heat exchanger is intended by the Technical Specification RHR pump Surveillance Requirements.

One of the Surveillance Requirements for the Suppression Pool Cooling (SPC) and Suppression Pool Spray (SPS) modes of the RHR system demonstrate that each RHR pump develops the required flowrate while operating in the applicable mode with flow through the associated heat exchanger and its closed bypass valve. Verifying that each RHR pump develops the required flow rate, while operating in the applicable mode with flow through the heat exchanger (after consideration of flow through the closed bypass valve), ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Code, Section XI. This test confirms one point on the pump baseline curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance.

During the SPC surveillance test, instrument uncertainty is accounted for by applying a flow penalty of 160 gpm to the acceptance criteria in the SPC surveillance. Therefore, the minimum flow rate through the heat exchanger for this surveillance test is 10,160 gpm. For the SPS surveillance, to account for instrument uncertainty, a flow margin of 40 gpm is applied to the acceptance criteria resulting in a minimum flow rate through the heat exchanger of 540 gpm. The surveillance test also measures the flow through the bypass valve. This flow rate is a measure of valve condition only and is not an acceptance criterion for the heat exchanger flow rate.

DEPRESSURIZATION SYSTEMS (Continued)

Under full power operating conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a water temperature of approximately 135°F immediately following blowdown which is below the 200°F used for complete condensation via mitered T-quencher devices. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is no dependency on containment overpressure during the accident injection phase. If both RHR loops are used for containment cooling, there is no dependency on containment overpressure for post-LOCA operations.

Experimental data indicates that excessive steam condensing loads can be avoided if the peak local temperature of the suppression pool is maintained below 200°F during any period of relief valve operation. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Because of the large volume and thermal capacity of the suppression pool, the volume and temperature normally changes very slowly and monitoring these parameters daily is sufficient to establish any temperature trends. By requiring the suppression pool temperature to be frequently recorded during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken. The requirement for an external visual examination following any event where potentially high loadings could occur provides assurance that no significant damage was encountered. Particular attention should be focused on structural discontinuities in the vicinity of the relief valve discharge since these are expected to be the points of highest stress.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety relief valve to assure mixing and uniformity of energy insertion to the pool.

In conjunction with the Mark I containment Long Term Program, a plant unique analysis was performed which demonstrated that the containment, the attached piping and internal structures meet the applicable structural and mechanical acceptance criteria for Hope Creek. The evaluation followed the design basis loads defined in the Mark I Load Definition Report, NEDO-21888, December 1978, as modified by NRC SER NUREG 0661, July 1980 and Supplement 1, August 1982, to ensure that hydrodynamic loads, appropriate for the life of the plant, were applied.

3/4.6.3 PRIMARY CONTAINMENT ISOLATION VALVES

The OPERABILITY of the primary containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A of 10 CFR 50. 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 LOCA.

Primary containment isolation valves covered by this LCO are listed in the Technical Requirements Manual.

The ACTIONS are modified by a Note allowing isolation valves closed to satisfy ACTION requirements to be reopened on an intermittent basis 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.

Surveillance 4.6.3.4 requires demonstration that a representative sample of reactor instrumentation line excess flow check valves are tested to demonstrate that the valve actuates to check flow on a simulated instrument line break. This surveillance requirement provides assurance that the instrument line EFCV's will perform so that the predicted radiological consequences will not be exceeded during a postulated instrument line break event as evaluated in the UFSAR. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. Operating experience has demonstrated that these components are highly reliable and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint.

3/4.6.4 VACUUM RELIEF

Suppression Chamber-to-Drywell Vacuum Breakers

BACKGROUND: The function of the suppression-chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are eight internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber that allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell-drywell boundary. Each vacuum breaker is a self-actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused by Emergency Core Cooling Systems flow from a recirculation line or main steam line break, or drywell spray actuation following a loss of coolant accident (LOCA).

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the waterleg in the vent system during normal operation.

<u>APPLICABLE SAFETY ANALYSES</u>: Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Section 6.2 and Appendix 6A of the Hope Creek UFSAR as part of the accident response of the primary containment systems. Internal (suppression chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary.

The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 0.20 psid. Additionally, one of the eight internal vacuum breakers is assumed to fail in a closed position. The results of the analyses show that the design pressure limits are not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that all eight vacuum breakers be OPERABLE are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The vacuum relief capacity between the drywell and suppression chamber should be 1/16 of the total main vent cross sectional area, with the valves set to operate at 0.20 psid differential pressure. Design Basis Accident (DBA) analyses require the vacuum breakers to be closed initially and to remain closed and leak tight.

The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of the NRC Policy Statement.

LCO: All eight vacuum breakers must be OPERABLE for opening and closed (except during testing or when the vacuum breakers are performing their intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber 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 OPERATIONAL CONDITIONS 1, 2, and 3, the Suppression Pool Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of this system. The vacuum breakers, therefore, are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3, when the Suppression Pool Spray System is required to be OPERABLE, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.

Also, in OPERATIONAL CONDITIONS 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in OPERATIONAL CONDITIONS 1, 2, and 3.

In OPERATIONAL CONDITIONS 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these OPERATIONAL CONDITIONS; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in OPERATIONAL CONDITION 4 or 5.

ACTIONS: With one of the required vacuum breakers inoperable for opening (e.g., the vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining seven OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one of the eight required vacuum breakers inoperable, 72 hours is allowed to restore at least one of the inoperable vacuum breakers to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event and the adequacy of the remaining vacuum breaker capability.

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that a differential pressure of 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The required 2 hour Completion Time is considered adequate to perform this test.

If the inoperable suppression chamber-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours and to OPERATIONAL CONDITION 4 within the following 24 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.

<u>SURVEILLANCE REQUIREMENTS</u>: Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that a differential pressure of 0.5 psid between the suppression chamber and drywell is maintained for 1 hour without makeup. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

A Note is added to this SR that allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers.

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. In addition, this functional test is required within 12 hours after a discharge of steam to the suppression chamber from the safety/relief valves.

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.20 psid is valid.

Reactor Building-to-Suppression Chamber Vacuum Breakers

BACKGROUND: The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a check type vacuum relief valve and an air operated butterfly valve located in series) in each of two lines from the reactor building to the suppression chamber airspace. The butterfly valve is actuated by differential pressure. The vacuum breaker is self-actuating and can be remotely operated for testing purposes. The two vacuum breakers in series must be closed to maintain a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent primary containment spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by heating and ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary 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 reactor building-to-suppression chamber vacuum breakers are presented in Section 6.2 and Appendix 6A of the Hope Creek UFSAR as part of the accident response of the containment systems. Internal (suppression-chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls, which form part of the primary containment boundary.

The safety analyses assume the external vacuum breakers to be closed initially and to be fully open at 0.25 psid. Additionally, of the two reactor building-to-suppression chamber vacuum breakers, one is assumed to fail in a closed position to satisfy the single active failure criterion. 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.

The reactor building-to-suppression chamber vacuum breakers satisfy Criterion 3 of the NRC Policy Statement.

LCO: All reactor building-to-suppression chamber vacuum breakers are required to be OPERABLE to satisfy the assumptions used in the safety analyses. The requirement ensures that the two vacuum breakers (vacuum breaker and air operated butterfly valve) in each of the two lines from the reactor building to the suppression chamber airspace are closed (except during testing or when performing their intended function). Also, the requirement ensures both vacuum breakers in each line will open to relieve a negative pressure in the suppression chamber.

APPLICABILITY: In OPERATIONAL CONDITIONS 1, 2, and 3, a DBA could cause pressurization of primary containment. In OPERATIONAL CONDITIONS 1, 2, and 3, the Suppression Pool Spray System is required to be OPERABLE to mitigate the effects of a DBA. Excessive negative pressure inside primary containment could occur due to inadvertent initiation of this system. Therefore, the vacuum breakers are required to be OPERABLE in OPERATIONAL CONDITIONS 1, 2, and 3, when the Suppression Pool Spray System is required to be OPERABLE, to mitigate the effects of inadvertent actuation of the Suppression Pool Spray System.

Also, in OPERATIONAL CONDITIONS 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in OPERATIONAL CONDITIONS 1, 2, and 3.

In OPERATIONAL CONDITIONS 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these OPERATIONAL CONDITIONS. Therefore, maintaining reactor building-to-suppression chamber vacuum breakers OPERABLE is not required in OPERATIONAL CONDITION 4 or 5.

ACTIONS: Action a: With one vacuum breaker assembly with one or two valves inoperable for opening, the leak tight primary containment boundary is intact. The ability to mitigate an event that causes a containment depressurization is threatened, however, if both vacuum breakers in at least one vacuum breaker assembly are not OPERABLE. Therefore, the inoperable vacuum breaker must be restored to OPERABLE status within 72 hours. This is consistent with the Completion Time for Action c and the fact that the leak tight primary containment boundary is being maintained.

Action b: With two vacuum breaker assemblies with one or more vacuum breakers inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breakers is lost. Therefore, both valves in one assembly must be restored to OPERABLE status within 1 hour. This 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.

Action c: With one or more vacuum breaker assemblies with one valve not closed, the leak tight primary containment boundary may be threatened. Therefore, the inoperable valves must be restored to OPERABLE status or the open vacuum breaker assembly valve closed within 72 hours. The 72 hour Completion Time is consistent with requirements for inoperable suppression-chamber-to-drywell vacuum breakers in LCO 3.6.4.1, "Suppression-Chamber-to-Drywell Vacuum Breakers." The 72 hour Completion Time takes into account the redundant capability afforded by the remaining valves, the fact that an OPERABLE valve in each of the assemblies is closed, and the low probability of an event occurring that would require the valves to be OPERABLE during this period.

Action d: With one or more vacuum breaker assemblies with two valves not closed, primary containment integrity is not maintained. Therefore, one open valve in each affected assembly must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

If all the valves in a vacuum breaker assembly cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, the plant must be brought to at least OPERATIONAL CONDITION 3 within 12 hours and to OPERATIONAL CONDITION 4 within the following 24 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.

<u>SURVEILLANCE REQUIREMENTS</u>: Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker position. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

A Note is added to this SR. The first part of the Note allows reactor-to-suppression chamber vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second part of the Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR.

Each vacuum breaker must be cycled to ensure that it opens properly to perform its design function and returns to its fully closed position. This ensures that the safety analysis assumptions are valid.

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.25 psid is valid.

3/4.6.5 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Reactor Building and associated structures provide secondary containment during normal operation when the drywell is sealed and in service. At other times the drywell may be open and, when required, secondary containment integrity is specified.

Establishing and maintaining a 0.25 inch water gage vacuum in the reactor building with the filtration recirculation and ventilation system (FRVS) once per 18 months, along with the surveillance of the doors, hatches, dampers and valves, is adequate to ensure that there are no violations of the integrity of the secondary containment.

SR 4.6.5.1.a is modified by a Note which states the SR is not required to be met for up to 4 hours if an analysis demonstrates that four FRVS recirculation units and one FRVS ventilation unit remain capable of establishing the required secondary containment vacuum. Use of the Note is expected to be infrequent but may be necessitated by situations in which secondary containment vacuum may be less than the required containment vacuum, such as, but not limited to, wind gusts or failure or change of operating normal ventilation subsystems. These conditions do not indicate any change in the leak tightness of the secondary containment boundary. The analysis should consider the actual conditions (equipment configuration, temperature, atmospheric pressure, wind conditions, measured secondary containment vacuum, etc.) to determine whether, if an accident requiring secondary containment to be OPERABLE were to occur, the above FRVS lineup could establish the assumed secondary containment vacuum within the time assumed in the accident analysis. If so, the SR may be considered met for a period up to 4 hours. The 4 hour limit is based on the expected short duration of the situations when the Note would be applied

The analysis referred to above has been performed for HCGS in a technical evaluation (ref. 70162724-0090) which modeled the drawdown capability of the above FRVS lineup. The technical evaluation documents that the FRVS lineup is capable of drawing down secondary containment from an initial atmospheric condition to 0.28 inches water gauge vacuum within 35 seconds. The ability of this FRVS lineup to maintain secondary containment is periodically demonstrated by the Reactor Building Integrity Functional Surveillance Test. The available margin between the FRVS performance documented in this analysis and the requirement assumed in the HCGS accident analysis to establish 0.25 inches water gauge vacuum within 375 seconds, accommodates any variation in drawdown performance during varying conditions of temperature, pressure and wind and meets the intent of the analysis described in the Note applied to SR 4.6.5.1.a.

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 secondary containment. Due to radioactive decay, handling of fuel only requires OPERABILITY of secondary containment when fuel being handled is recently irradiated, i.e., fuel that has occupied part of the critical reactor core within the previous 24 hours.

During handling of fuel and CORE ALTERATIONS, secondary containment and FRVS actuation is not required. However, building ventilation will be operating during fuel handling and CORE ALTERATIONS and will be capable of drawing air into the building and exhausting through a monitored pathway. To reduce doses even further below that provided by 24 hours of natural decay, a single normal or contingency method to promptly close secondary containment penetrations is provided in accordance with RG 1.183. Such prompt methods need not completely block the penetration or be capable of resisting pressure. The purpose of the “prompt methods” (defined as within 30 minutes) is to enable ventilation systems to draw the release from a postulated fuel handling accident in the proper direction such that it can be treated and monitored. These contingencies are to be utilized after a postulated fuel handling accident has occurred to reduce doses even further below that provided by the natural decay.

3/4.6.6 PRIMARY CONTAINMENT ATMOSPHERE CONTROL

The primary containment oxygen concentration is maintained less than 4% by volume to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

The primary containment oxygen concentration must be less than 4% by volume when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in OPERATIONAL CONDITION 1, since this is the condition with the highest probability of an event that could produce hydrogen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is less than 15% of RATED THERMAL POWER, the potential for an event that generates significant hydrogen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these “windows,” when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

If oxygen concentration is $\geq$ 4% by volume at any time while operating in OPERATIONAL CONDITION 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4% by volume within 24 hours. The 24 hour completion time is allowed when oxygen concentration is $\geq$ 4% by volume because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

If oxygen concentration cannot be restored to within limits within the required completion time, the plant must be brought to an OPERATIONAL CONDITION in which the LCO does not apply. To achieve this status, plant must be in at least STARTUP within 8 hours. The 8 hour completion time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

The primary containment must be determined to be inert by verifying that oxygen concentration is less than 4% by volume. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

3/4.7.1 SERVICE WATER SYSTEMS

The OPERABILITY of the station service water and the safety auxiliaries cooling systems ensures that sufficient cooling capacity is available for continued operation of the SACS and its associated safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

TS 3.7.1.3 LCO allows continued plant operation above 88°F provided that the both emergency discharge (EOB) valves are open and the emergency discharge pathways are available and that only a single EDG, SACS pump or SSWS pump can be inoperable. The action to open both EOB valves eliminates the need to assume a random failure of an emergency discharge flow path. The emergency discharge flow path is the assumed discharge flow path of the service water system in the unlikely event the normal, non-seismic flow path (discharge to the cooling tower basin) is unavailable during either the LOCA or LOP event. The 30-day allowed outage times of the SACS TS 3.7.1.1 and SSWS TS 3.7.1.2 are based on having a SACS or SSWS pump out of service and having the capability to withstand an additional pump failure in the same system.

SACS TS 3.7.1.1 actions a.1.b (for one SACS heat exchanger inoperable), a.2 (for one SACS subsystem otherwise inoperable), a.3.a (for one SACS pump in each subsystem inoperable) and SSWS TS 3.7.1.2 actions a.2 (for one SSWS pump in each loop inoperable) and a.3 (for one SSWS loop otherwise inoperable), contain the statement “if continued plant operation is permitted by LCO 3.7.1.3.” Continued plant operation in these actions is permitted up to a UHS temperature of 88.0°F (Calculation EG-0047). If the UHS temperature were to exceed 88.0°F while in the identified SACS or SSWS TS actions, Action a of TS 3.7.1.3 would be entered. The completion time of the above SACS or SSWS TS actions will run in conjunction with the shutdown action ‘a’ of TS 3.7.1.3. If the UHS temperature were to return below 88.0°F, TS 3.7.1.3 Action a would be exited; however, the allowed outage time of SACS TS 3.7.1.1 actions a.1.b, a.2, a.3.a and SSWS TS 3.7.1.2 actions a.2 and a.3 would continue from the initial entry time.

Above 88.0°F, TS 3.7.1.3 allows a single SACS pump or SSWS pump or EDG to be inoperable for a period of 72 hours. This 72 hour allowed outage time in TS 3.7.1.3 is not intended to extend the allowed outage times of TS 3.7.1.1 Action a.1.a, 3.7.1.2 Action a.1 or 3.8.1.1 Actions b.2 and b.3 for an inoperable SACS pump, SSWS pump or EDG. If a SACS pump, or SSWS pump or EDG is inoperable prior to river temperature increasing above 88ºF, the allowed outage time limits of TS 3.7.1.1, 3.7.1.2 or 3.8.1.1 continue from the initial entry of these actions. If the UHS temperature is above 88ºF and a SACS pump, or SSWS pump or EDG is declared inoperable, both the action of TS 3.7.1.3 and the action of either TS 3.7.1.1 Action 1.a, TS 3.7.1.2 Action a.1 or TS 3.8.1.1 Actions b.2 or b.3 are entered concurrently.

With water temperature of the UHS > 91°F, the design basis assumption associated with initial UHS temperature are bounded provided the temperature of the UHS averaged over the previous 24 hour period is ≤ 91°F. With the water temperature of the UHS > 91°F, long term cooling capability of the ECCS loads and DGs may be affected. Therefore, to ensure long term cooling capability is provided to the ECCS loads when water temperature of the UHS is > 91°F, the action is to more frequently monitor the water temperature of the UHS and verify the temperature is ≤ 91°F when averaged over the previous 24 hour period. The once per hour Completion Time takes into consideration UHS temperature variations and the increased monitoring frequency needed to ensure design basis assumptions and equipment limitations are not exceeded in this condition. If the water temperature of the UHS exceeds 91°F when averaged over the previous 24 hour period or the water temperature of the UHS exceeds 93°F, the applicable Action must be entered immediately.

3/4.7.2 CONTROL ROOM SYSTEMS

3/4.7.2.1 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

The OPERABILITY of the control room emergency filtration system ensures that the control room will remain habitable for occupants during and following all design basis accident conditions. Operation with the heaters on for ≥ 15 continuous minutes demonstrates OPERABILITY of the system. Periodic operation ensures that heater failure, blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Program. The OPERABILITY of this

CONTROL ROOM EMERGENCY FILTRATION SYSTEM (Continued)

system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less total effective dose equivalent (TEDE). This limitation is consistent with the requirements of 10 CFR Part 50.67, “Accident Source Term.”

Due to radioactive decay, handling of fuel only requires OPERABILITY of CREF when fuel being handled is recently irradiated, i.e., fuel that has occupied part of the critical reactor core within the previous 24 hours. Each CREF subsystem is considered OPERABLE when the individual components necessary to limit Control Room Envelope occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. Fans are OPERABLE (i.e., one CREF fan, one control room supply fan and one control room return air fan);

b. HEPA filter and charcoal adsorbers are not excessively restricting flow and are capable of performing their filtration functions, and

c. Heater, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

The Control Room Envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and other non-critical areas including adjacent support offices, toilet and utility rooms. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, ceiling, ducting, valves, 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.

In order for the CREFAS 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 entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, immediate action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

Immediate action(s), in accordance with the LCO Action Statements, means that the required action should be pursued without delay and in a controlled manner.

Surveillance Requirement 4.7.2.1.2 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.

3/4.7.2.2 CONTROL ROOM AIR CONDITIONING (AC) SYSTEM

The control room supply AC portion of the Control Room Heating, Ventilation, and Air Conditioning (HVAC) System (hereafter referred to as the Control Room AC System) provides temperature control for the control room following isolation of the control room. The Control Room AC 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, one control room chilled water subsystem (which provides cooling water to the cooling coils), ductwork, dampers, and instrumentation and controls to provide for control room temperature control. The Control Room AC System is designed to provide a controlled environment under both normal and accident conditions. Each control room chilled water subsystem includes a centrifugal water chiller, a chilled water circulating pump, head tank, controls, piping, and valves.

The Control Room AC 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, compressors, ductwork, dampers, and associated instrumentation and controls. Due to radioactive decay, the Control Room AC System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours.

With one Control Room AC subsystem inoperable, the inoperable Control Room AC subsystem must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE Control Room AC subsystem is adequate to perform the control room air 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 allowed outage 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.

If both Control Room AC subsystems are inoperable, the Control Room AC System may not be capable of performing its intended function. Therefore, the control room area temperature is required to be monitored to ensure that temperature is being maintained low enough that equipment in the control room is not adversely affected. With the control room temperature being maintained within the temperature limit, 72 hours is allowed to restore a Control Room AC subsystem to OPERABLE status. This allowed outage time is reasonable considering that the control room temperature is being maintained within limits and the low probability of an event occurring requiring control room isolation.

The provisions of Specification 3.0.3 are not applicable in OPERATIONAL CONDITION* If moving recently irradiated fuel assemblies while in OPERATIONAL CONDITION 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

3/4.7.3 Deleted

3/4.7.4 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the Emergency Core Cooling System equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor steam dome pressure exceeds 150 psig. This pressure is substantially below that for which the RCIC system can provide adequate core cooling for events requiring the RCIC system.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2 and 3 when reactor vessel steam dome pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period.

A Note prohibits the application of LCO 3.0.4.b to an inoperable RCIC system. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable RCIC system and the provisions of LCO 3.0.4.b, which allow entry into an OPERATIONAL CONDITION 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.

REACTOR CORE ISOLATION COOLING SYSTEM (Continued)

The surveillance requirements provide adequate assurance that RCIC will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to start cooling at the earliest possible moment.

3/4.7.5 DELETED

3/4.7.6 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4.7.7 MAIN TURBINE BYPASS SYSTEM

The main turbine bypass system is required to be OPERABLE consistent with the assumptions of the feedwater controller failure analysis for FSAR Chapter 15.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least one of the onsite A.C. and the corresponding D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. or D.C. source.

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering an OPERATIONAL CONDITION or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into an OPERATIONAL CONDITION 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.

The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources," December 1974 as modified by plant specific analysis and diesel generator manufacturer recommendations. When two diesel generators are inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generators as a source of emergency power, are also OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period two or more of the diesel generators are inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

LCO 3.8.1.1, Action b allows the AOT for EDG "A" or "B" to extend from 72 hours to 14 days provided the availability of the supplemental power source is verified within the initial 72-hour period and once per 12 hours thereafter. The supplemental power source provides additional defense-in depth during the extended AOT.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

When utilizing the extended "A" or "B" EDG AOT (greater than 72 hours and less than or equal to 14 days), the following regulatory commitments shall be implemented. (Reference 1):

1. When either the A or B EDG is removed from service for an extended 14-day AOT, both HPCI and RCIC shall be operable.

2. Component testing or maintenance of safety systems and important non safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or LOOP will be avoided. In addition, no discretionary switchyard maintenance will be performed (Reference 2).

3. Voluntary entry into this extended 14 day AOT should not be scheduled if adverse weather conditions are expected.

4. Operating crews will be briefed on the EDG work plan and procedural actions regarding LOOP and SBO, prior to entering the extended 14 day EDG AOT.

If one or more of the above commitments is not met while in the extended completion time, the corrective action program shall be entered, the risk managed in accordance with the Maintenance Rule, and the commitment(s) restored without delay.

The 14 day AOT for the "C" and "D" EDGs is based upon the following conditions being met:

1. Hope Creek should verify through Technical Specifications, procedures or detailed analyses that the systems, subsystems, trains, components and devices that are required to mitigate the consequences of an accident are available and operable before removing an EDG for extended preventative maintenance (PM). In addition, positive measures should be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components and devices while the EDG is inoperable.

2. The overall unavailability of the EDG should not exceed the performance criteria developed for implementation of 10CFR50.65 requirements as described in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," as endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," June 1993.

3. When the "C" or "D" EDG is removed from service for an extended 14 day AOT, any two of the remaining EDGs must be capable, operable and available to mitigate the consequences of a LOOP condition.

4. The removal from service of safety systems and important non-safety equipment, including offsite power sources, should be minimized during the extended 14 day AOT.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

5. Entry into this LCO should not be abused by repeated voluntary entry into and exit from the LCO. The primary intent of the extended EDG AOT is that the extended EDG AOT from 72 hours to 14 days may be needed to perform preplanned EDG maintenance such as teardowns and modifications that would otherwise extend beyond the original 72 hour AOT.

6. Any component testing or maintenance that increases the likelihood of a plant transient should be avoided. Plant operation should be stable during the extended 14 day AOT.

7. Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.

For proper operation of the standby EDGs, it is necessary to ensure the proper quality of the fuel oil. USNRC Regulatory Guide 1.137 addresses the recommended fuel oil practices as supplemented by ANSI N195-1976. The fuel oil properties governed by these surveillance requirements are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity) and impurity level.

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 and Chapter 15, assume Engineered Safety Feature (ESF) systems are operable. The EDGs 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.

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation based on three of the four EDGs running continuously. 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 EDGs 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. EDG day tank fuel oil requirements, as well as transfer capability from the storage tanks to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Because stored diesel supports LCO 3.8.1 and LCO 3.8.2, the stored diesel fuel oil is required to be within limits when the associated EDG is required to be operable.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

For specification 6.8.4.e, the tests listed are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tanks. The tests, limits and applicable ASTM standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057

b. Verify in accordance with the tests specified in ASTM D975 that the sample has an absolute specific gravity at 60/60°F of ≥ 0.83 and ≤ 0.89 or an API gravity at 60°F of ≥ 27 and ≤ 39 for low sulfur (S500) No. 2-D diesel fuel oil, or an absolute specific gravity at 60/60°F of ≥ 0.82 and ≤ 0.88 or an API gravity at 60°F of ≥ 30 and ≤ 42 for ultra low sulfur (S15) No. 2-D diesel fuel oil, a kinematic viscosity of 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil bulk water and sediment are within limits for ASTM D2709 for Grade No. 2-D Fuel Oil.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO concern since the fuel oil is not added to the storage tanks.

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975 are met for the new fuel oil when tested in accordance with ASTM D975 except that the analysis for sulfur may be performed in accordance with ASTM D2622 for low sulfur S500 No. 2-D fuel oil and that for ultra low sulfur S15 No. 2-D fuel oil in accordance with ASTM D5453.

The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on EDG operation. This surveillance ensures the availability of high quality fuel oil for the EDGs.

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.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Particulate concentration should be determined in accordance with ASTM D2276, Method A, or ASTM D5452. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. The 0.8 micron filters specified in ASTM D2276 or ASTM D5452 may be replaced with membrane filters up to 3.0 microns. This is acceptable since the closest tolerance fuel filter in the HC EDGs is a five micron particle retention duplex filter on the engine driven fuel oil pump. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. The total volume of stored fuel oil contained in two or more interconnected tanks must be considered and tested separately. The frequency of this test takes into consideration fuel oil degradation trends that indicate the particulate concentration is unlikely to change significantly between frequency intervals.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

With exceptions as noted in the Hope Creek UFSAR, the surveillance requirements for demonstrating the OPERABILITY of the diesel generators comply with the recommendations of Regulatory Guide 1.9, “Selection, Design, and Qualification of Diesel Generator Units Used as Standby (Onsite) Electrical Power Systems at Nuclear Power Plants," Revision 2, December, 1979, Regulatory Guide 1.108, “Periodic Testing of Diesel Generator Units Used as Onsite Electrical Power Systems at Nuclear Power Plants," Revision 1, August 1977 and Regulatory Guide 1.137 “Fuel-Oil Systems for Standby Diesel Generators," Revision 1, October 1979 as modified by plant specific analysis, diesel generator manufacturer’s recommendations, and Amendment 59, to the Facility Operating License, issued November 22, 1993.

SR 4.8.1.2 requires the SRs from LCO 3.8.1.1 that are necessary for ensuring the OPERABILITY of the AC sources not in OPCONs 1, 2 and 3. SRs 4.8.1.1.2.a.5, 4.8.1.1.2.g, 4.8.1.1.2.h.4, 4.8.1.1.2.h.5, 4.8.1.1.2.h.6, 4.8.1.1.2.h.7, 4.8.1.1.2.h.13 and 4.8.1.1.2.k.2. are not applicable in OPCONs 4, 5 and * because EDG start and load within a specified time and response on an offsite power or ECCS initiation signal is not required. SR 4.8.1.1.2.h.11 is not required to be met because the required OPERABLE EDG(s) is not required to undergo periods of being synchronized to the offsite circuit.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The minimum voltage and frequency stated in the Surveillance Requirements (SRs) are those necessary to ensure the EDG can accept Design Basis Accident loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing EDG OPERABILITY, but a time constraint is not imposed. This is because a typical EDG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR (for example if a significant negative trend develops). In lieu of a time constraint in the SR, PSEG Nuclear LLC will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause an EDG to become inoperable.

SRs 4.8.1.1.2.a.5 and 4.8.1.1.2.k.1 are modified by Notes stating momentary transients outside the load range do not invalidate the test. The Notes recognize that there are external grid conditions that can cause a shift in load sharing with the EDG and allow the operator time to recognize and adjust load back into the band without invalidating the performance of the surveillance.

The surveillance requirements for demonstrating the OPERABILITY of the unit batteries are in accordance with the recommendations of Regulatory Guide 1.129 "Maintenance Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants," February 1978 and IEEE Std 450-1980, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations."

Verifying average electrolyte temperature above the minimum for which the battery was sized, total battery terminal voltage on float charge, connection resistance values and the performance of battery service and discharge tests ensures the effectiveness of the charging system, the ability to handle high discharge rates and compares the battery capacity at that time with the rated capacity.

Table 4.8.2.1-1 specifies the normal limits for each designated pilot cell and each connected cell for electrolyte level, float voltage and specific gravity. The limits for the designated pilot cells float voltage and specific gravity, greater than 2.13 volts and .015 below the manufacturer's full charge specific gravity or a battery charger current that had stabilized at a low value, is characteristic of a charged cell with adequate capacity. The normal limits for each connected cell for float voltage and specific gravity, greater than 2.13 volts and not more than .020 below the manufacturer's full charge specific gravity with an average specific gravity of all the connected cells not more than .010 below the manufacturer's full charge specific gravity, ensures the OPERABILITY and capability of the battery.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

Operation with a battery cell's parameter outside the normal limit but within the allowable value specified in Table 4.8.2.1-1 is permitted for up to 31 days. During this 31 day period: (1) the allowable values for electrolyte level ensures no physical damage to the plates with an adequate electron transfer capability; (2) the allowable value for the average specific gravity of all the cells, not more than .020 below the manufacturer's recommended full charge specific gravity ensures that the decrease in rating will be less than the safety margin provided in sizing; (3) the allowable value for an individual cell's specific gravity, ensures that an individual cell's specific gravity will not be more than .040 below the manufacturer's full charge specific gravity and that the overall capability of the battery will be maintained within an acceptable limit; (4) the allowable value for an individual cell's float voltage, greater than 2.07 volts, ensures the battery's capability to perform its design function; (5) the TABLE 4.8.2.1-1 NOTATION 31 day ACTION time was derived taking into consideration that while battery capacity is degraded, sufficient capacity exists to perform the intended function while providing a time period adequate to permit full restoration of the battery cell parameters to normal limits.

"Energized" 120 VAC distribution panels [A-D]J48[1/2] require the panels to be energized to their proper voltage from the associated inverter via inverted DC voltage, inverter using the normal AC source, or Class 1E backup AC source via voltage regulator. OPERABLE inverters require the associated 120 VAC distribution panels ([A-D]J48[1/2]) to be powered by the inverter with output voltage within tolerances, and power input to the inverter from the associated station battery. Alternatively, the power supply may be from an internal AC source via rectifier as long as the OPERABLE station battery is available as the uninterruptible power supply.

REFERENCES

1. Amendment No. 188, March 25, 2011

2. NUREG-0800 Branch Technical Position 8-8, Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions, February 2012 (ADAMS Accession No. ML113640138)

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Primary containment electrical penetrations and penetration conductors are protected by demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers by periodic surveillance.

The surveillance requirements applicable to lower voltage circuit breakers provides assurance of breaker reliability by testing one representative sample of each manufacturers brand of circuit breaker. Each manufacturer's molded case and metal case circuit breakers are grouped into representative samples which are than tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

ELECTRICAL EQUIPMENT PROTECTIVE DEVICES (Continued)

The OPERABILITY or bypassing of the motor operated valves thermal overload protection continuously or during accident conditions by integral bypass devices ensures that the thermal overload protection during accident conditions will not prevent safety related valves from performing their function. The Surveillance Requirements for demonstrating the OPERABILITY or bypassing of the thermal overload protection continuously or during accident conditions are in accordance with Regulatory Guide 1.106 "Thermal Overload Protection for Electric Motors on Motor Operated Valves," Revision 1, March 1977. The list of MOVs required to have thermal overload bypass circuitry is contained in UFSAR Table 8.3-11.

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radiation.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. The flux need not be monitored for the first sixteen bundles loaded before a SPIRAL RELOAD or for the last sixteen bundles unloaded during a SPIRAL UNLOAD. In the case of the SPIRAL RELOAD, the sixteen bundles loaded may be different from the bundles scheduled to occupy the bundle locations for the next cycle provided; (i) the cold reactivity of any unscheduled bundle temporarily loaded is individually less than the cold reactivity of the respective bundle scheduled for the subject location, (ii) the uncontrolled k-infinity of the lattice is less than 1.31, and (iii) the bundles are arranged in four two-by-two arrays surrounding an SRM with each array having a minimum of 12 inches between it and an adjacent array.

A SPIRAL RELOAD or SPIRAL UNLOAD can have various implementations consistent with the general guidance provided in Definitions 1.44 and 1.45, respectively.

A SPIRAL RELOAD implementation must have the following characteristics:

1) Spiral movements are used to enhance symmetry of the fuel bundles around the SRMs (i.e. enhanced SRM redundancy, enhanced SRM response).
2) The first fuel bundles to be installed are those immediately surrounding each SRM to generate at least 3 cps (up to four bundles per SRM).
3) The first stage of spiral movements establishes a single fueled region containing the SRMs (i.e. enhanced neutron coupling).
4) The intermediate stages of spiral movements maintain a single fueled region containing the SRMs (i.e. enhanced neutron coupling, no unmonitored fuel).
5) The last stage of spiral movements starts at the SRMs and moves outward to the periphery.

A SPIRAL UNLOAD implementation must have the following characteristics:

1) Spiral movements are used to enhance symmetry of the fuel bundles around the SRMs (i.e. enhanced SRM redundancy, enhanced SRM response).
2) The first stage of spiral movements starts at the periphery and moves inward toward the SRMs.
3) The intermediate stages of spiral movements are chosen to maintain a single fueled region containing the SRMs (i.e. enhanced neutron coupling, no unmonitored fuel).

INSTRUMENTATION (Continued)

4) The last stage of spiral movements leaves up to four bundles immediately surrounding each SRM to maintain at least 3 cps.
5) The last fuel bundles to be removed are those immediately surrounding each SRM.
6) Prior to the start of a SPIRAL UNLOAD, fuel bundles may be removed as long as the removals do not impact the above characteristics.

A "fueled region" is a group of adjacent fuel bundles (preferably face-adjacent) containing at least one SRM. The region can have interior "holes" (i.e. positions without fuel bundles).

Fuel Loading Chambers (FLCs, "Dunking Chambers") can be substituted for SRMs as long as they are connected to the SRM circuitry.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS minimizes the possibility that fuel will be loaded into a cell without a control rod, although one rod may be withdrawn under control of the reactor mode switch refuel position one-rod-out-interlock.

3/4.9.4 DELETED

3/4.9.5 DELETED

3/4.9.6 DELETED

3/4.9.7 DELETED

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL - SPENT FUEL STORAGE POOL

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirement that at least one residual heat removal loop be OPERABLE or that an alternate method capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation ensures that (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F as required during REFUELING, and (2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication.

The requirement to have two shutdown cooling mode loops OPERABLE when there is less than 22 feet 2 inches of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and 22 feet 2 inches of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event a failure of the operating RHR loop, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core.

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD WORTH MINIMIZER

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirements ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations during open vessel testing requires additional restrictions in order to ensure that criticality is properly monitored and controlled. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

The material originally contained in this Technical Specification was deleted with the issuance of Amendment No. 35. However, to maintain the historical reference to this specification, this section has been intentionally left blank.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

The material originally contained in Bases Section 3/4.10.7 was deleted with the issuance of Amendment No. 14. However, to maintain the historical reference to this section, Bases Section 3/4.10.7 is intentionally left blank.

3/4.10.8 INSERVICE LEAK AND HYDROSTATIC TESTING

This special test exception allows reactor vessel inservice leak and hydrostatic testing to be performed in OPERATIONAL CONDITION 4 with reactor coolant temperatures ≤ 212°F. The additionally imposed OPERATIONAL CONDITION 3 requirement for SECONDARY CONTAINMENT operability provides conservatism in the response of the unit to an operational event. This allows flexibility since temperatures approach 200°F during the testing and can drift higher because of decay and mechanical heat.

3/4.11.1 Deleted

3/4.11.1.2 Deleted

3/4.11.1.3 Deleted

3/4.11.1.4 LIQUID HOLDUP TANKS

The tanks listed in this specification include all those outdoor radwaste tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System.

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area.

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 Deleted

3/4.11.2.2 Deleted

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3/4.11.2.4 Deleted

3/4.11.2.5 Deleted

3/4.11.2.6 Deleted

3/4.11.2.7 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

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3/4.11.3 Deleted

3/4.11.4 Deleted

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BASES

3/4.12.1 Deleted

3/4.12.2 Deleted

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