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November 7, 2001

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DOCKET NUMBER 50-483
CALLAWAY PLANT
UNION ELECTRIC COMPANY
TECHNICAL SPECIFICATION BASES REVISION 2

Furnished herewith is the signed original and 10 copies of Revision 2 to the Callaway Plant Technical Specification Bases in accordance with 10 CFR 50.4(b)(6).

Pursuant to 10 CFR 50.71(e), the Technical Specification Bases has been revised to include all of the change made since our revision 0 issue, December 15, 2000 to October 19, 2001.

If there are any questions, please contact us.

Very truly yours,

JBlosser

John D. Blosser
Manager, Regulatory Affairs

BFH/jdg

Enclosure: Directions for Replacement Pages
Attachment: Revision 2 to Callaway Plant Technical Specification Bases

A001

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9 copies sent to J. Donohew

Rec'd at NRC/DCD 12/04/01

STATE OF MISSOURI)
)   S S
CITY OF ST. LOUIS)

John D. Blosser, of lawful age, being first duly sworn upon oath says that he is Manager, Regulatory Affairs for Union Electric Company; that he has read the foregoing document and knows the content thereof; that he has executed the same for and on behalf of said company with full power and authority to do so; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

By JBlosser
John D. Blosser
Manager, Regulatory Affairs

SUBSCRIBED and sworn to before me this 7th day of November, 2001.

Melissa L. Orr

MELISSA L. ORR
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November 9, 2001

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability that the minimum departure from nucleate boiling ratio (DNBR) of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNBR correlation being used (the WRB-2 correlation for VANTAGE 5 fuel for most safety analyses). The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95% probability with 95% confidence that DNB will not occur when the minimum DNBR is at the DNBR limit (1.17 for the WRB-2 correlation). In meeting this design basis, for ITDP analyses, uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95% probability with 95% confidence level that the minimum DNBR for the limiting rod is greater than or equal to the DNBR limit. The uncertainties in the above plant parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty, combined with the correlation DNBR limit, establishes a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties. The design DNBR values are 1.33 and 1.34 for thimble and typical cells, respectively, for VANTAGE 5 fuel. In addition, margin has been maintained by meeting safety analysis DNBR limits of 1.61 and 1.69 for thimble and typical cells, respectively, for VANTAGE 5 fuel. The design DNBRs of 1.33 and 1.35 (STD/OFA) and 1.33 and 1.34 (V5) are considered design bases limits for fission barriers for consideration in the 10 CFR 50.59 process. Reference 5 discusses three transients analyzed with the W-3 DNBR correlation.

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

(continued)

BASES

BACKGROUND (continued)

temperature. Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant. Reference 6 further discusses the fuel centerline temperature design basis.

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

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

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

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

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System Allowable Values in Table 3.3.1-1, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Protection for these reactor core SLs is provided by the steam generator safety valves and the following automatic reactor trip functions:

a. High pressurizer pressure trip;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required within 24 hours after achieving equilibrium conditions (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because flux maps are taken in equilibrium conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation.

The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$.

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

The W(Z) curve is provided in the COLR for discrete core elevations. Flux map data are typically taken for 30 to 75 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

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

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

The top and bottom 15% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. When $F_Q^C(Z)$ is measured, an evaluation of the expression below is required to account for any increase to $F_Q(Z)$ that may occur and cause the $F_Q(Z)$ limit to be exceeded before the next required $F_Q(Z)$ evaluation.

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

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

it is required to meet the $F_Q(Z)$ limit with the last $F_Q^W(Z)$ increased by the appropriate factor specified in the COLR, or to evaluate $F_Q(Z)$ more frequently, each 7 EFPD. These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP, or at a reduced power at any other time, and verifying the inferred results for 100% RTP meet the 100% RTP $F_Q(Z)$ limit, provides assurance that the $F_Q(Z)$ limit will be met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, within 24 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

c. Safety Injection - Containment Pressure - High 1 (continued)

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties. The Trip Setpoint is ≤ 3.5 psig.

Containment Pressure - High 1 must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection - Pressurizer Pressure - Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) atmospheric steam dump valve or safety valve;
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer PORV or safety valve;
- LOCAs; and
- SG Tube Rupture.

The pressurizer pressure channels provide both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, SI, and automatic PORV actuation. Therefore, the actuation logic must be able to withstand both an input failure to control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four logic.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

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

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environment instrument uncertainties. The Trip Setpoint is ≥ 1849 psig.

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11 and below P-11 unless the Safety Injection - Pressurizer Pressure - Low Function is blocked) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure - High 1 signal.

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection - Steam Line Pressure

Steam Line Pressure - Low

Steam Line Pressure - Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG atmospheric steam dump valve or an SG safety valve.

Steam Line Pressure - Low provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

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

disabled. The Trip Setpoint reflects only steady state instrument uncertainties. The Trip Setpoint is ≤ 1970 psig.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

9. Automatic Pressurizer PORV Actuation

For the inadvertent ECCS actuation at power event (a Condition II event), the safety analysis (Ref. 15) credits operator actions from the main control room to terminate flow from the normal charging pump (NCP) and to open at least one PORV block valve (assumed to initially be closed) and assure the availability of the PORV for automatic pressure relief. Analysis results indicate that water relief through the pressurizer safety valves, which could result in the Condition II event degrading into a Condition III event if the safety valves did not reseat, is precluded if operator actions are taken within the times assumed in the Reference 15 analysis to terminate NCP flow and to assure at least one PORV is available for automatic pressure relief. The assumed operator action times conservatively bound the times measured during simulator exercises. Therefore, automatic PORV operation is an assumed safety function in MODES 1, 2, and 3. The PORVs are equipped with automatic actuation circuitry and manual control capability. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions (Ref. 15) to open the associated block valves (if closed) and to assure the PORV handswitches are in the automatic operation position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator actions.

a. Automatic Pressurizer PORV Actuation – Automatic Actuation Logic and Actuation Relays (SSPS)

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

described for Function 1.b, except that the LCO is not applicable in MODE 4 as discussed below for Function 9.b.

b. Automatic Pressurizer PORV Actuation – Pressurizer Pressure – High

This signal provides protection against an inadvertent ECCS actuation at power event. Pressurizer pressure provides both control and protection functions: input to the Pressurizer Pressure Control System, reactor trip, SI, and automatic PORV actuation. Therefore, the actuation logic must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with a two-out-of-four opening logic. The Trip Setpoint is ≤2335 psig.

The automatic PORV opening logic is satisfied when two-out-of-four (2/4) pressurizer pressure channels exceed their setpoint. Continued operation is allowed with one inoperable channel in the tripped condition. In this case, the automatic opening logic would revert to one-out-of-three (1/3). A single failure (e.g., failed bistable card) in one of the remaining three channels could result in both PORVs opening and remaining open since the automatic closure logic requires three-out-of-four (3/4) channels to reset, which could not be satisfied with two inoperable channels. However, this event can be terminated by PORV block valve closure and the consequences of this event are bounded by the analysis of a stuck open pressurizer safety valve in Reference 16. Therefore, automatic PORV closure is not a required safety function and the OPERABILITY requirements are satisfied by four OPERABLE pressurizer pressure channels.

Consistent with the Applicability of LCO 3.4.11, "Pressurizer PORVs," the LCO for Function 9 is not applicable in MODE 4 when both pressure and core energy are decreased and transients that could cause an overpressure condition will be slow to occur. This is also consistent with the Applicability of Functions 1.c, 1.d, and 1.e. LCO 3.4.12 addresses automatic PORV actuation instrumentation requirements in MODES 4 (with any RCS cold leg temperature ≤275°F), 5, and 6 with the reactor vessel head in place.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY (continued)

The ESFAS instrumentation satisfies Criterion 3 of 10CFR50.36(c)(2)(ii).

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified on a per steam line, per SG, per pump, etc., basis, then the Condition may be entered separately for each steam line, SG, pump, etc., as appropriate.

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

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

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

Condition B applies to manual initiation of:

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

(continued)

BASES

ACTIONS (continued)

- Phase B Isolation.

This action addresses the train orientation of the SSPS for the functions listed above. If a channel or train is inoperable, 48 hours are allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the channel or train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2, C.3.1, and C.3.2

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

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

This action addresses the train orientation of the SSPS and the master and slave relays. Containment Isolation Phase A is the primary signal to ensure closing of the containment purge supply and exhaust valves. If one Phase A train is inoperable, operation may continue as long as the Required Action to place and maintain containment purge supply and exhaust valves in their closed position is met. Required Action C.1 is modified by a Note that this Action is only required if Containment Phase A Isolation (Function 3.a.(2)) is inoperable. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring

(continued)

BASES

ACTIONS

C.1, C.2, C.3.1, and C.3.2 (continued)

during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 5 within an additional 30 hours (42 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of Reference 8 that 4 hours is the average time required to perform channel surveillance.

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

Condition D applies to:

- Containment Pressure - High 1;
- Pressurizer Pressure - Low;
- Steam Line Pressure - Low;
- Containment Pressure - High 2;
- Steam Line Pressure - Negative Rate - High;
- SG Water Level - Low Low (Adverse Containment Environment);
- SG Water Level - Low Low (Normal Containment Environment); and
- Pressurizer Pressure – High.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic (excluding Pressurizer Pressure – Low, Pressurizer Pressure – High, and SG Water Level - Low Low (Adverse and Normal Containment Environment)). Therefore, failure of one channel (i.e., with the bistable not tripped) places the Function in a two-out-of-two configuration. The

(continued)

BASES

ACTIONS

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

inoperable channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

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

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 4 hours allowed for testing, are justified in Reference 8.

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

Condition E applies to:

- Containment Spray Containment Pressure - High 3; and
- Containment Phase B Isolation Containment Pressure - High 3.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypassed

(continued)

BASES

ACTIONS

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

condition within 6 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 4 hours for surveillance testing. Placing a second channel in the bypassed condition for up to 4 hours for testing purposes is acceptable based on the results of Reference 8.

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

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a channel or train is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

BASES

ACTIONS (continued)

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

Condition G applies to the automatic actuation logic and actuation relays (SSPS) for the Steam Line Isolation, Turbine Trip and Feedwater Isolation, and AFW actuation Functions. Condition G also applies to the MSFIS automatic actuation logic.

The action addresses the train orientation of the actuation logic for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Refs. 8 and 13) assumption that 4 hours is the average time required to perform channel surveillance.

H.1

Condition H applies to the automatic logic and actuation relays (SSPS) for the Automatic Pressurizer PORV Actuation Function.

The Required Action addresses the impact on the ability to mitigate an inadvertent ECCS actuation at power event that requires the availability of at least one pressurizer PORV for automatic pressure relief. With one or more automatic actuation logic trains inoperable, the associated pressurizer PORV(s) must be declared inoperable immediately. This requires that Condition B or E of LCO 3.4.11, "Pressurizer PORVs," be entered immediately depending on the number of PORVs inoperable.

The Required Action is modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Refs. 8

(continued)

BASES

ACTIONS (continued)

and 13) assumption that 4 hours is the average time required to perform channel surveillance.

I.1 and I.2

Condition I applies to:

- SG Water Level - High High (P-14).

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-three logic will result in actuation. The 6 hour Completion Time is justified in Reference 8. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 4 hours for surveillance testing of other channels. The 6 hours allowed to place the inoperable channel in the tripped condition, and the 4 hours allowed for an inoperable channel to be in the bypassed condition for testing, are justified in Reference 8.

J.1 and J.2

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

This action addresses the train orientation of the BOP ESFAS for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by providing automatic start of the AFW System pumps. If a channel is inoperable, 1 hour is allowed to place it in the tripped condition. If the channel cannot be tripped in 1 hour, 6 additional hours are allowed to place the unit in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 2 hours for surveillance testing of other channels.

(continued)

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ACTIONS (continued)

K.1, K.2, K.3.1, and K.3.2

Condition K applies to:

- RWST Level - Low Low Coincident with Safety Injection.

RWST Level - Low Low Coincident With SI provides actuation of switchover to the containment recirculation sumps. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. This Action Statement limits the duration that an RWST level channel could be tripped, due to its being inoperable or for testing, in order to limit the probability for automatic switchover to an empty containment sump upon receipt of an inadvertent safety injection signal (SIS), coincident with a single failure of another RWST level channel, or for premature switchover to the sump after a valid SIS. This sequence of events would start the RHR pumps, open the containment sump RHR suction valves and, after meeting the sump suction valve open position interlock, the RWST RHR suction valves would close. The 72 hour restoration time for an inoperable channel is consistent with that given in other Technical Specifications affecting RHR operability, e.g., for one ECCS train inoperable and for one diesel generator inoperable.

The Completion Times are justified in Reference 8. If the channel cannot be placed in the tripped condition within 6 hours and returned to OPERABLE status within 72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The Required Actions are modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 4 hours for surveillance testing of other channels. This bypass allowance is justified in Reference 8.

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

Condition L applies to the P-11 interlock.

With one or more required channel(s) inoperable, the operator must verify that the interlock is in the required state for the existing unit condition by observation of the associated permissive annunciator window. This

(continued)

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ACTIONS

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

action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

M.1 and M.2

Condition M applies to the Trip Time Delay (TTD) circuitry enabled for the SG Water Level-Low Low trip Functions when THERMAL POWER is less than or equal to 22.41% RTP in MODES 1 and 2. With one or more Vessel ΔT Equivalent (Power-1, Power-2) channel(s) inoperable, the associated Vessel ΔT channel(s) must be placed in the tripped condition within 6 hours. If the inoperability impacts the Power-1 and Power-2 portions of the TTD circuitry (e.g., Vessel ΔT RTD failure), both the Power-1 and Power-2 bistables in the affected protection set(s) are placed in the tripped condition. However, if the inoperability is limited to either the Power-1 or Power-2 portion of the TTD circuitry, only the corresponding Power-1 or Power-2 bistable in the affected protection set(s) is placed in the tripped condition. With one or more TTD circuity delay timer(s) inoperable, both the Vessel ΔT (Power-1) and Vessel ΔT (Power-2) channels are tripped. This automatically enables a zero time delay for that protection channel with either the normal or adverse containment environment level bistable enabled. The Completion Time of 6 hours is based on Reference 11. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. The unit must be placed in MODE 3 within an additional six hours.

N.1, N.2.1, and N.2.2

Condition N applies to the Environmental Allowance Modifier (EAM) circuitry for the SG Water Level-Low Low trip Functions in MODES 1, 2, and 3. With one or more EAM channel(s) inoperable, they must be

(continued)

BASES

ACTIONS

N.1, N.2,1, and N.2.2 (continued)

placed in the tripped condition within 6 hours. Placing an EAM channel in trip automatically enables the SG Water Level-Low Low (Adverse Containment Environment) bistable for that protection channel, with its higher SG level Trip Setpoint (a higher trip setpoint means a feedwater isolation or an AFW actuation would occur sooner). The Completion Time of 6 hours is based on Reference 11. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. The unit must be placed in MODE 3 within an additional six hours and in MODE 4 within the following six hours.

O.1 and O.2

Condition O applies to the Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low trip Function. The Condensate Storage Tank is the highly reliable and preferred suction source for the AFW pumps. This function has a two-out-of-three trip logic. Therefore, continued operation is allowed with one inoperable channel until the performance of the next monthly COT on one of the other channels, as long as the inoperable channel is placed in trip within 1 hour. Condition O is modified by a Note stating that LCO 3.0.4 is not applicable. MODE changes are permitted with an inoperable channel.

P.1

Condition P applies to the Auxiliary Feedwater Manual Initiation trip Function. The associated auxiliary feedwater pump(s) must be declared inoperable immediately when one or more channel(s) is inoperable. Refer to LCO 3.7.5, "Auxiliary Feedwater (AFW) System."

Q.1 and Q.2

Condition Q applies to the Auxiliary Feedwater Balance of Plant ESFAS automatic actuation logic and actuation relays. With one train inoperable, the unit must be brought to MODE 3 within 6 hours and MODE 4 within the following 6 hours. The Required Actions are modified by a Note that allows one train to be bypassed for up to 2 hours for surveillance testing provided the other train is OPERABLE.

(continued)

BASES

ACTIONS (continued)

R.1, R.2.1, and R.2.2

Condition R applies to the Auxiliary Feedwater Loss of Offsite Power trip Function. With the inoperability of one or both train(s), 48 hours are allowed to return the train(s) to OPERABLE status. The specified Completion Time is reasonable considering this Function is only associated with the turbine driven auxiliary feedwater pump (TDAFP), the available redundancy provided by the motor driven auxiliary feedwater pumps, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and in MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the TDAFP for mitigation.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

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

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 31 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypassed condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. In addition, SR 3.32.2 is the performance of an ACTUATION LOGIC TEST of the MSFIS PLC actuation logic, initiated from the SSPS slave relays. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.3

SR 3.3.2.3 is the performance of an ACTUATION LOGIC TEST using the BOP ESFAS automatic tester. The continuity check does not have to be performed, as explained in the Note. This SR is applied to the balance of plant actuation logic and relays that do not have circuits installed to perform the continuity check. This test is required every 31 days on a STAGGERED TEST BASIS. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4

SR 3.3.2.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 31 days on a STAGGERED TEST BASIS. The time allowed for the testing (4 hours) and the surveillance interval are justified in Reference 8.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

A COT is performed on each required channel to ensure the channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The Frequency of 92 days is justified in Reference 8.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.6 (continued)

test is performed every 92 days. The SR is modified by a Note that excludes slave relays K602, K620, K622, K624, K630, K740, and K741 which are included in testing required by SR 3.3.2.13 and SR 3.3.2.14. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a TADOT every 18 months. This test is a check of the AFW pump start on Loss of Offsite Power trip Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The trip actuating devices tested within the scope of SR 3.3.2.7 are the LSELS output relays and BOP ESFAS separation groups 1 and 4 logic associated with the automatic start of the turbine driven auxiliary feedwater pump on an ESF bus undervoltage condition.

The Frequency is adequate. It is based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints for relays. The trip actuating devices tested have no associated setpoint.

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. The Manual Safety Injection TADOT shall independently verify OPERABILITY of the undervoltage and shunt trip handswitch contacts for both the Reactor Trip Breakers and Reactor Trip Bypass Breakers as well as the contacts for safety injection actuation. It is performed every 18 months. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency is adequate, based on industry operating

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.8 (continued)

experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of Reference 6.

The Frequency of 18 months is based on the assumed calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified via response time testing per SR 3.3.2.10.

Whenever an RTD is replaced in Function 5.e.(3) or 6.d.(3), the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

The portion of the automatic PORV actuation circuitry required for COMS is calibrated in accordance with SR 3.4.12.9.

SR 3.3.2.10

This SR verifies the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response time verification acceptance criteria are included in Reference 9. No credit was taken in the safety analyses for those channels with response times listed as N.A. No response time testing

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

requirements apply where N.A. is listed in Reference 9. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position). The safety analyses include the sum of the following response time components:

a. Process delay times (e.g., scoop transport delay and thermal lag associated with the narrow range RCS RTDs used in the SG low-low level Vessel ΔT (Power-1, Power-2) functions) which are not testable;

b. Sensing circuitry delay time from the time the trip setpoint is reached at the sensor until an ESFAS actuation signal is generated by the SSPS (response time testing associated with LSELS and BOP-ESFAS is discussed under SR 3.3.5.4 and SR 3.3.6.6);

c. Any intentional time delay set into the trip circuitry (e.g., NLL cards (lag) and NPL cards (PROM logic cards for trip time delay) associated with the SG low-low level Vessel ΔT (Power-1, Power-2) trip functions, NLL cards (lead/lag) associated with the steam line pressure high negative rate trip function) to add margin or prevent spurious trip signals; and

d. The time for the final actuation devices to reach the required functional state (e.g., valve stroke time, pump or fan spin-up time).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. Time constants are verified during the performance of SR 3.3.2.9. The response time may be verified by a series of overlapping tests, or other verification (e.g., Ref. 10 and Ref. 14), such that the entire response time is verified.

Response time may be verified by actual response time tests in any series of sequential, overlapping, or total channel measurements, or by the summation of allocated sensor, signal processing, and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests); (2) inplace, onsite, or offsite (e.g. vendor)

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.10 (continued)

test measurements; or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response

Time Testing Requirements," provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," provides the basis and methodology for using allocated signal processing and actuation logic response time in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in References 10 and 14 may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

ESF RESPONSE TIME verification is performed on an 18 month STAGGERED TEST BASIS. Each verification shall include at least one train such that both trains are verified at least once per 36 months. Testing of the final actuation devices, which make up the bulk of the response time, is included in the verification of each channel. The final actuation device in one train is tested with each channel. Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

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

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT for the P-4 Reactor Trip Interlock. A successful test of the required contact(s) of a channel relay

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.11 (continued)

may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The 18 month Frequency is based on operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint. This TADOT does not include the circuitry associated with steam dump operation since it is control grade circuitry.

SR 3.3.2.12

SR 3.3.2.12 is the performance of a monthly COT on ESFAS Function 6.h, "AFW Pump Suction Transfer on Suction Pressure - Low." A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL OPERATIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

A COT is performed to ensure the channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

SR 3.3.2.13

SR 3.3.2.13 is the performance of a SLAVE RELAY TEST as described in SR 3.3.2.6, except that SR 3.3.2.13 has a Note specifying that it applies only to slave relays K602, K622, K624, K630, K740, and K741. These slave relays are tested with a Frequency of 18 months and prior to entering MODE 4 for Functions 1.b, 3.a.(2), and 7.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days (Reference 12). The 18 month Frequency for these slave relays is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.14

SR 3.3.2.14 is the performance of a SLAVE RELAY TEST as described in SR 3.3.2.6, except that SR 3.3.2.14 has a Note specifying that it applies only to slave relays K620 and K750. These slave relays are tested with a Frequency of 18 months and prior to entering MODE 3 for Functions 5.a and 9.a whenever the unit has been in MODE 5 or 6 for > 24 hours, if not performed within the previous 92 days. The 18 month Frequency for these slave relays is based on the need to perform this Surveillance under the conditions that apply during a unit outage to avoid the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The SLAVE RELAY TEST of relay K620 does not include the circuitry associated with the main feedwater pump trip solenoids since that circuitry serves no required safety function. The 18 month Frequency for slave relay K620 was accepted by NRC at initial plant licensing based on Reference 12. The 18 month Frequency for slave relay K750 is consistent with that of SR 3.4.11.2 in LCO 3.4.11, "Pressurizer PORVs," which in turn is based on the NRC-approved Inservice Test (IST) program relief request BB-10 on the pressurizer PORVs (Ref. 17). Testing slave relay K750 at power would result in opening the PORVs and depressurizing the RCS. If the PORV block valves are closed, there is not enough pressure to open the PORVs.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 15.
4. IEEE-279-1971.
5. 10 CFR 50.49.
6. Callaway Setpoint Methodology Report (NSSS), SNP (UE)-565 dated May 1, 1984, and Callaway Instrument Loop Uncertainty Estimates (BOP), J-U-GEN.
7. Not used.
8. Callaway OL Amendment No. 64 dated October 9, 1991.
9. FSAR Section 16.3, Table 16.3-2.
10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

(continued)

BASES

REFERENCES (continued)

11. Callaway OL Amendment No. 43 dated April 14, 1989.

12. SLNRC 84-0038 dated February 27, 1984.

13. Callaway OL Amendment No. 117 dated October 1, 1996.

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

15. FSAR, Section 15.5.1.

16. FSAR, Section 15.6.1.

17. Letter from Mel Gray (NRC) to Garry L. Randolph (UE), "Revision 20 of the Inservice Testing Program for Callaway Plant, Unit 1 (TAC No. MA4469)," dated March 19, 1999.

Table B 3.3.2-1
(Page 1 of 5)

FUNCTION				NOMINAL TRIP SETPOINT [(a)]
1.	Safety Injection			
	a.	Manual Initiation		N.A.
	b.	Automatic Actuation Logic and Actuation Relays (SSPS)		N.A.
	c.	Containment Pressure - High 1		≤ 3.5 psig
	d.	Pressurizer Pressure - Low		≥ 1849 psig
	e.	Steam Line Pressure – Low		≥ 615 psig
2.	Containment Spray			
	a.	Manual Initiation		N.A.
	b.	Automatic Actuation Logic and Actuation Relays (SSPS)		N.A.
	c.	Containment Pressure High-3		≤ 27.0 psig
3.	Containment Isolation			
	a.	Phase A Isolation		
		(1)	Manual Initiation	N.A.
		(2)	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
		(3)	Safety Injection	See Function 1 (Safety Injection).

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-1
(Page 2 of 5)

FUNCTION			NOMINAL TRIP SETPOINT [a]
	b.	Phase B Isolation	
		(1) Manual Initiation	N.A.
		(2) Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
		(3) Containment Pressure High-3	≤ 27.0 psig
4.	Steam Line Isolation		
	a.	Manual Initiation	N.A.
	b.	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
	c.	Automatic Actuation Logic and Actuation Relays (MSFIS)	N.A.
	d.	Containment Pressure - High 2	≤ 17.0 psig
	e.	Steam Line Pressure	
		(1) Low	≥ 615 psig
		(2) Negative Rate - High	≤ 100 psi with a rate/lag controller time constant ≥ 50 sec.

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-1
(Page 3 of 5)

FUNCTION			NOMINAL TRIP SETPOINT [(a)]
5.	Turbine Trip and Feedwater Isolation		
	a.	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
	b.	Automatic Actuation Logic and Actuation Relays (MSFIS)	N.A.
	c.	SG Water Level - High High (P-14)	≤ 78% of narrow range instrument span
	d.	Safety Injection	See Function 1 (Safety Injection).
	e.	SG Water Level Low-Low	See Function 6.d, SG Water Level Low-Low.
6.	Auxiliary Feedwater		
	a.	Manual Initiation	N.A.
	b.	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
	c.	Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	N.A.
	d.	SG Water Level - Low Low	
		(1) Steam Generator Water Level - Low Low (Adverse Containment Environment)	≥ 20.2% of narrow range instrument span

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-1
(Page 4 of 5)

FUNCTION	NOMINAL TRIP SETPOINT [(a)]
d. SG Water Level - Low Low (continued)	
(2) Steam Generator Water Level - Low Low (Normal Containment Environment)	≥ 14.8% of narrow range instrument span
(3) Vessel ΔT Equivalent including delay timers - Trip Time Delay	
(a) Vessel ΔT (Power-1)	≤ Vessel ΔT Equivalent to 12.41% RTP (with a time delay ≤ 232 sec.)
(b) Vessel ΔT (Power-2)	≤ Vessel ΔT Equivalent to 22.41% RTP (with a time delay ≤ 122 sec.)
(4) Containment Pressure - Environmental Allowance Modifier	≤ 1.5 psig
e. Safety Injection	See Function 1 (Safety Injection).
f. Loss of Offsite Power	N.A.
g. Trip of all Main Feedwater Pumps	N.A.
h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low	≥ 21.71 psia

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-1
(Page 5 of 5)

FUNCTION			NOMINAL TRIP SETPOINT [(a)]
7.	Automatic Switchover to Containment Sump		
	a.	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
	b.	Refueling Water Storage Tank (RWST) Level - Low Low	≥ 36%
		Coincident with Safety Injection	See Function 1 (Safety Injection).
8.	ESFAS Interlocks		
	a.	Reactor Trip, P-4	N.A.
	b.	Pressurizer Pressure, P-11	≤ 1970 psig
9.	Automatic Pressurizer PORV Actuation		
	a.	Automatic Actuation Logic and Actuation Relays (SSPS)	N.A.
	b.	Pressurizer Pressure – High	≤2335 psig

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

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BASES

ACTIONS

G.1 (continued)

provide an alternate means for RVLIS. These three parameters provide diverse information to verify there is adequate core cooling. When Containment Radiation Level (High Range) monitors (GTRIC0059 and GTRIC0060 or GTRR0060) are inoperable, the area radiation monitors inside containment are used as an alternate method below 10 R/hr and portable survey equipment with the capability to detect gamma radiation over the range 1E-03 to 1E0 4 is used above 10R/hr.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The RM-23 unit display for loop GTR-0059 and either the RM-23 unit display or the GTRR0060 recorder for loop GTR-0060 must be used to perform the CHANNEL CHECK of the Containment Radiation Level (High Range) monitors.

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

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized. The containment hydrogen analyzers are not normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. Neutron detectors are excluded from the CHANNEL CALIBRATION because it is impractical to set up a test that demonstrates and adjusts neutron detector response to known values of the parameter (neutron flux) that the channel monitors. The Note applies to the Gamma-Metrics fission chambers associated with the indicators discussed in the LCO Bases. Containment Radiation Level (High Range) CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10R/hr and a one point calibration check of the detector below 10R/hr with an installed or portable gamma source. The Frequency is based on operating experience and consistency with the typical industry refueling cycle. During performance of the CHANNEL CALIBRATION for the Containment Radiation Level (High Range) monitors, verification of the RM-23 unit display and alarm functions is required. In addition, recorder GTRR0060 is included in the CHANNEL CALIBRATION of loop GTR-0060.

Whenever an RTD is replaced in Functions 2 or 3, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. Whenever a core exit thermocouple is replaced in Functions 14, 15, 16, or 17, the next required CHANNEL CALIBRATION of the core exit thermocouples is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

REFERENCES

1. FSAR Appendix 7A.

2. NRC Letter, "Callaway Plant, Unit 1 - Emergency Response Capability - Conformance to Regulatory Guide 1.97, Revision 2," B.J. Youngblood to D.F. Schnell, dated April 10, 1985.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) with an operating loop's temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "PHYSICS TESTS Exceptions - MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with operating RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow operating RCS loop average temperatures to fall below $T_{no\ load}$, which may cause operating RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 551°F every 12 hours.

The SR to verify operating RCS loop average temperatures every 12 hours takes into account indications and alarms that are continuously available to the operator in the control room and is consistent with other routine Surveillances which are typically performed once per shift. In addition, operators are trained to be sensitive to RCS temperature during approach to criticality and will ensure that the minimum temperature for criticality is met as criticality is approached.

REFERENCES

1. FSAR, Chapter 15.

BASES

ACTIONS

B.1 (continued)

of offsite power would be unlikely in this period. Pressure control may be maintained during this time using the remaining OPERABLE backup pressurizer heater group or the variable heater group.

C.1 and C.2

If one group of backup pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is consistent with the safety analyses assumption of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated backup pressurizer heaters are verified to be at their design rating. This is done by energizing the heaters and measuring circuit current. The Frequency of 18 months is considered adequate to detect heater degradation.

REFERENCES

1. FSAR, Chapter 15.
2. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are of the pop type. The valves are spring loaded and self actuated by direct fluid pressure with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are self actuating, they are considered independent components. The minimum relief capacity for each valve, 420,000 lb/hr at 2485 psig plus 3% accumulation, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves which is divided equally between the three valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, 5, and 6 with the reactor vessel head on; however, in MODE 4 with one or more RCS cold leg temperatures ≤ 275°F, MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Cold Overpressure Mitigation System (COMS)."

The upper and lower pressure limits are based on the tolerance requirements assumed in the safety analyses. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

(continued)

BASES

BACKGROUND (continued)	The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal at full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load/turbine trip;

d. Loss of normal feedwater;

e. Loss of non-emergency AC power to station auxiliaries;

f. Locked rotor;

g. Feedwater line break; and

h. Rod cluster control assembly ejection.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation occurs in the FSAR Chapter 15 analysis of events c, f, and g (above) and may be required for any of the above events to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at 2460 psig (slightly below the RCS design pressure of 2485 psig), and within the specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the tolerance requirements assumed in the safety analyses.

(continued)

BASES

LCO (continued)

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the COMS arming temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 with any RCS cold leg temperature ≤ 275°F, MODE 5, or MODE 6 with the reactor vessel head on because COMS is in service. Overpressure protection is not required in MODE 6 with the reactor vessel head removed (vent path ≥ 2 square inches).

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperature ≤ 275°F within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperatures at or below 275°F, overpressure protection is provided by the COMS. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ±2% for OPERABILITY; however, the valves are reset to ±1% during the Surveillance to allow for drift.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 15.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are safety-related DC solenoid operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive seat leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the block valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The power supplies to the PORVs and their block valves are Class 1E. The automatic pressure relief signal actuation circuitry, the manual controls, and the cold overpressure mitigation system (COMS) portion of the actuation circuitry are also Class 1E. The PORVs and their associated block valves are powered from two separate safety trains (Ref. 2).

The plant has two PORVs, each having a relief capacity of 210,000lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure -High reactor trip setpoint for all design transients up to and including the design step load decrease with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for cold

(continued)

BASES

BACKGROUND (continued)	overpressure mitigation. See LCO 3.4.12, "Cold Overpressure Mitigation System (COMS)."

APPLICABLE SAFETY ANALYSES

Plant operators may employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

For the inadvertent ECCS actuation at power event (a Condition II event), the safety analysis (Ref. 1) credits operator actions from the main control room to terminate flow from the normal charging pump (NCP) and to open a PORV block valve (assumed to initially be closed) and assure the availability of at least one PORV for automatic pressure relief. Analysis results indicate that water relief through the pressurizer safety valves, which could result in the Condition II event degrading into a Condition III event if the safety valves did not reseat, is precluded if operator actions are taken within the times assumed in the Reference 1 analysis to terminate NCP flow and to assure at least one PORV is available for automatic pressure relief. The assumed operator action times conservatively bound the times measured during simulator exercises. Therefore, automatic PORV operation is an assumed safety function in MODES 1, 2, and 3. The PORVs are equipped with automatic actuation circuitry and manual control capability. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions (Ref. 1) to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic operation position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator actions.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR), pressurizer volume, or hot leg saturation criteria are examined (Ref. 3). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint. The DNBR calculation is more conservative, the pressurizer water volume is maximized, and the hot leg saturation temperature is reduced for those transients assuming

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV operation. Events that assume this condition include turbine trip, loss of normal feedwater, loss of non-emergency AC power to station auxiliaries, and the feedline break case with no SI (Ref. 3). Automatic operation is assumed in the Reference 3 analyses , but operation of the PORVs has a detrimental impact on the results of the analysis.

Pressurizer PORVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

The LCO also requires the PORVs and their automatic actuation circuitry to be OPERABLE, in conjunction with the capability to manually open their associated block valves and assure the availability of the PORVs for automatic pressure relief, to mitigate the effects associated with an inadvertent ECCS actuation at power event. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions (Ref. 1) to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic operation position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator actions.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized, or closed and energized, with the capability to be cycled, since the required safety functions of the block valve are accomplished by manual operation to cycle the block valve. Although typically open to allow PORV operation, the block valve may be OPERABLE when closed to isolate the flow path of an inoperable PORV because of excessive seat leakage. Isolation of an OPERABLE PORV does not render that PORV or block valve inoperable, provided the automatic pressure relief function remains available with timely operator actions (Ref. 1) to open the associated block valve, if closed, and assure the PORV's handswitch is in the automatic operation position. Satisfying the LCO helps minimize challenges to fission product barriers and precludes water relief through the pressurizer safety valves.

An OPERABLE PORV must not be experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criterion, exists when conditions dictate closure of the block valve to limit leakage.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are required to be OPERABLE in MODES 1, 2, and 3 for automatic pressure relief to fulfill the required function of minimizing challenges to the pressurizer safety valves during an inadvertent ECCS actuation event. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODE 4 when both pressure and core energy are decreased and the pressure surges become much less significant. The PORV setpoint is reduced for COMS in MODES 4 (with any RCS cold leg temperature $\leq$ 275°F), 5, and 6 with the reactor vessel head in place. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

Note 1 has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis). The exception for LCO 3.0.4, Note 2, permits MODE changes with inoperable PORVs or block valves as one possible recourse to remaining in the Applicability of LCO 3.4.12.

A.1

The PORVs may be inoperable because of excessive seat leakage yet capable of automatic pressure relief and capable of being manually cycled. In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valves must be closed, but power must be maintained to the associated block valves, since removal of power would render the block valve inoperable. Credit for automatic PORV operation is taken in the Reference 1 safety analysis. However, the PORVs are considered OPERABLE in either the manual or automatic mode, as long as the automatic actuation circuitry is OPERABLE and the PORV can be made available for automatic pressure relief by timely operator actions (Ref. 1). Although a PORV may be designated inoperable, it may be available for automatic pressure relief and capable of being manually opened and closed and, therefore, able to perform its required safety functions.

(continued)

BASES

ACTIONS

A.1 (continued)

PORV inoperability solely due to excessive seat leakage does not prevent automatic and manual use and does not create a possibility for a small break LOCA. Closure of the block valve(s) establishes reactor coolant pressure boundary (RCPB) integrity for a PORV(s) with excessive seat leakage. RCPB integrity takes priority over the capability of the PORV(s) to mitigate an overpressure event. For these reasons, the block valve may be closed but the Action requires power be maintained to the valve. This Condition is only intended to permit operation of the plant for a limited period of time not to exceed the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition. Normally, the PORVs should be available for automatic mitigation of overpressure events and should be returned to OPERABLE and automatic actuation status prior to entering startup (MODE 2).

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

B.1, B.2, and B.3

If one PORV is inoperable for reasons other than excessive seat leakage (i.e., not capable of automatic pressure relief or not capable of being manually cycled), it must be either restored or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times for Required Actions B.1 and B.2 of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable PORV cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to MODE 4, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not fully open. If the block valve is restored within the Completion Time of 72 hours, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant must be brought to MODE 4, as required by Condition D.

The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of automatic pressure relief or not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 1, 2, 3, and 4 (with any RCS cold leg temperature ≤ 275°F), 5, and 6 (with the reactor vessel head on), automatic PORV OPERABILITY is required. See LCO 3.4.12 for requirements in MODES 4, 5, and 6.

(continued)

BASES

ACTIONS (continued)

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

If more than one PORV is inoperable for reasons other than excessive seat leakage, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If one PORV is restored and one PORV remains inoperable, then the plant will be in Condition B with the time clock started at the time the remaining PORV was discovered to be inoperable. If no PORVs are restored within the Completion Time, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 1, 2, 3, and 4 (with any RCS cold leg temperature $\leq$ 275°F), 5, and 6 (with the reactor vessel head on), automatic PORV OPERABILITY is required. See LCO 3.4.12 for requirements in MODES 4, 5, and 6.

F.1 and F.2

If more than one block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

The Required Actions are modified by a Note stating that the Required Actions do not apply if the sole reason for the block valve being declared inoperable is as a result of power being removed to comply with other Required Actions. In this event, the Required Actions for inoperable PORV(s) (which require the block valve power to be removed once it is closed) are adequate to address the condition. While it may be desirable to also place the PORV(s) in manual control, this may not be possible for all causes of Condition B or E entry with PORV(s) inoperable and not capable of automatic pressure relief or not capable of being manually cycled (e.g., as a result of failed control power fuse(s) or control switch malfunction(s)).

(continued)

BASES (continued)

ACTIONS (continued)

G.1 and G.2

If the Required Actions of Condition F are not met, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 1, 2, 3, and 4 (with any RCS cold leg temperature ≤ 275°F), 5, and 6 (with the reactor vessel head on), automatic PORV OPERABILITY is required. See LCO 3.4.12 for requirements in MODES 4, 5, and 6.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed. The basis for the Frequency of 92 days is the ASME Code, Section XI (Ref. 4).

The Note modifies this SR by stating that it is not required to be performed with the block valve closed, in accordance with the Required Actions of this LCO. Opening the block valve in this condition increases the risk of an unisolable leak from the RCS since the PORV is already inoperable.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. Operating experience has shown that these valves usually pass the Surveillance when performed at the required Inservice Testing Program frequency. The Frequency is acceptable from a reliability standpoint.

REFERENCES

1. FSAR Section 15.5.1.
2. Regulatory Guide 1.32, February 1977.
3. FSAR, Section 15.2.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Cold Overpressure Mitigation System (COMS)

BASES

BACKGROUND

The COMS controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the COMS MODES, as approved by NRC for Callaway in Ref. 12.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires both safety injection pumps and one centrifugal charging pump to be incapable of injection into the RCS and isolating the accumulators. The normal charging pump (NCP) has been analyzed as capable of injecting during an overpressure transient and the analysis assumes the flow from one centrifugal charging pump and the NCP. The term "centrifugal charging pump" or "CCP" refers to the safety-related ECCS pumps only. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

(continued)

BASES

ACTIONS (continued)

monitoring system are inoperable. This allowance is provided because other instrumentation is available to monitor for RCS leakage.

A.1 and A.2

A primary system leak would result in reactor coolant flowing into the containment normal sumps or into the instrument tunnel sump. Indication of increasing sump level is transmitted to the control room by means of individual sump level transmitters. This information is used to provide the measurement of low leakage by monitoring level increase versus time.

With the required containment sump level and flow monitoring system inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere particulate radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Restoration of the required sump level and flow monitoring system to OPERABLE status within a Completion Time of 30 days is required to regain the function after the system's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

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

With the containment atmosphere particulate radioactivity monitoring instrumentation channel inoperable, alternative action is required. Either samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Samples of the containment atmosphere are obtained and analyzed for gaseous and particulate radioactivity.

(continued)

BASES

ACTIONS

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

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere particulate radioactivity monitor.

The 24 hour interval provides periodic information that is adequate to detect leakage. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

C.1.1, C.1.2, C.2.1, and C.2.2

With the required containment atmosphere gaseous radioactivity monitor and the required containment cooler condensate monitoring system inoperable, the means of detecting leakage are the containment sump level and flow monitoring system and the containment atmosphere particulate radioactivity monitor. This Condition does not provide all the required diverse means of leakage detection. With the containment atmosphere gaseous radioactivity monitoring and containment cooler condensate monitoring system instrumentation channels inoperable, alternative action is required. Either samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed every 24 hours to provide alternate periodic information. Samples of the containment atmosphere are obtained and analyzed for gaseous and particulate radioactivity. A Note is added allowing that SR 3.4.13.1 is not required to be performed until 12 hours after establishing steady state operation (stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. The followup Required Action is to restore either of the inoperable required monitoring methods to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.2 (continued)

is normally stable and is protected by a low level alarm set above the required water volume, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

SR 3.5.4.3

The boron concentration of the RWST should be verified every 7 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. FSAR, Chapter 6 and Chapter 15.
2. RFR-17070A.
3. FSAR Section 6.2.1.5 and Table 15.6-11.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

This LCO is applicable to Callaway since the plant utilizes the centrifugal charging pumps for safety injection (SI). The function of the seal injection throttle valves during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the centrifugal charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI.

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging pumps. The safety analyses make assumptions with respect to: (1) both the maximum and minimum total system resistance; (2) both the maximum and minimum branch injection line resistance; and (3) the maximum and minimum ranges of potential pump performance. These resistances and ranges of pump performance are used to calculate the maximum and minimum ECCS flows assumed in the safety analyses. The CCP maximum total pump flow SR in FSAR Section 16.5 ensures the maximum injection flow limit of 550 gpm is not exceeded. This value of flow is comprised of the total flow to the four branch lines of 469 gpm and a seal injection flow of 79 gpm plus 2 gpm for instrument uncertainties. The Bases for LCO 3.5.2, "ECCS - Operating," contain additional discussion on the safety analyses. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

This LCO ensures that seal injection flow will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small break

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the centrifugal charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory. Seal injection flow satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 2).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is established by adjusting the RCP seal water injection throttle valves such that flow to the RCP seals is limited to 20 gpm per pump in the event of a large break LOCA. This accident analysis limit is met by positioning the valves so that the flow to each RCP seal is 7.5± 0.5 gpm with a 105 (+5, -2) psi differential between the charging header and RCS pressure. Once set, these throttle valves are secured with locking devices and mechanical position stops. These devices help to ensure that the following safety analyses assumptions remain valid: (1) both the maximum and minimum total system resistance; (2) both the maximum and minimum branch injection line resistance; and (3) the maximum and minimum ranges of potential pump performance. These resistances and pump performance ranges are used to calculate the maximum and minimum ECCS flows assumed in the LOCA analyses of Reference 1. The centrifugal charging pump discharge header pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed differential pressure result in a conservative valve position should RCS pressure decrease.

The limit on seal injection flow must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these

(continued)

BASES

APPLICABILITY (continued)	MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual seal injection throttle valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limits. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

B.1 and B.2

When the Required Action cannot be completed within the required Completion Time, a controlled shutdown must be initiated. The Completion Time of 6 hours for reaching MODE 3 from MODE 1 is a reasonable time for a controlled shutdown, based on operating experience and normal cooldown rates, and does not challenge plant safety systems or operators. Continuing the plant shutdown begun in Required Action B.1, an additional 6 hours is a reasonable time, based on operating experience and normal cooldown rates, to reach MODE 4 where this LCO is no longer applicable.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Verification every 18 months that the manual seal injection throttle valves are adjusted to give a flow within the limit ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained. The seal water injection throttle valves are set to ensure proper flow resistance and pressure drop in the piping to each injection point in the event of a LOCA. The seal injection flow line resistance is established by adjusting the RCP seal water injection throttle valves such that flow to the RCP seals is limited to 20 gpm per pump in the event of a large break LOCA. This accident analysis limit is met by positioning the valves so that the flow to each RCP seal is 7.5 ± 0.5 gpm with a 105 (+5, -2) psi differential between the charging header and RCS pressure.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1 (continued)

Once set, these throttle valves are secured with locking devices and mechanical position stops. The Frequency of 18 months is based on engineering judgment and the controls placed on the positioning of these valves. The Frequency has proven to be acceptable through operating experience.

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ±20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual seal injection throttle valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

REFERENCES

1. FSAR, Sections 6.3 and 15.6.5.

2. 10 CFR 50.46.

BASES

BACKGROUND (continued)

Containment Shutdown Purge System (36 inch purge valves)

The Containment Shutdown Purge System operates to supply outside air into the containment for ventilation and cooling or heating needed for prolonged containment access following a shutdown and during refueling. The system may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 36 inch Containment Purge and exhaust valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, either the 36 inch Containment Shutdown Purge supply and exhaust isolation valves are normally maintained closed and blind flanges are installed or sealed closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Containment Mini-purge System (18 inch purge valves)

The Containment Mini-purge System operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access, and

b. Equalize containment internal and external pressures.

Since the 18 inch valves used in the Mini-purge System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment shutdown purge and mini-purge

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

valves) are minimized. The safety analyses assume that the 36 inch Containment Shutdown Purge and 18 inch Mini-Purge valves are closed at event initiation, however, the penetration flow paths may be isolated by blind flanges.

The DBA analysis assumes that isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a.

The LOCA offsite dose analysis assumes leakage from the containment at a maximum leak rate of 0.20 percent of the containment air weight per day for the first 24 hours, and at 0.10 percent of the containment air weight per day for the duration of the accident.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the 18 inch containment mini-purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard isolation valves are pneumatically operated spring closed valves that will fail closed on the loss of air.

The 36 inch Containment Shutdown Purge and exhaust valves may be unable to close against containment pressure following a LOCA. Therefore, either each of the Containment Shutdown Purge and exhaust valves is required to remain sealed closed during MODES 1, 2, 3, and 4 or closed and blind flanges must be installed. The Containment Shutdown Purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch Containment Purge valves must be maintained sealed

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The CST satisfies Criterion 3 and 4 of 10 CFR 50.36 (c)(2)(ii).

LCO

To satisfy analysis assumptions, the CST must contain sufficient cooling water to remove decay heat for four hours following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure.

The required CST contained water volume is ≥ 281,000 gallons, which is based on a cooldown to RHR entry conditions during a Station Blackout event. This basis is established in Reference 2.

The OPERABILITY of the CST is determined by maintaining the tank contained water volume at or above the minimum required volume.

APPLICABILITY

In MODES 1, 2, and 3, the CST is required to be OPERABLE.

In MODES 4, 5, or 6, the CST is not required because the AFW system is not required.

ACTIONS

A.1 and A.2

If the CST contained water volume is not within limits, the OPERABILITY of the backup ESW supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup ESW supply must include verification that the flow paths from the backup water supply (ESW system) to the AFW pumps are OPERABLE, and that the backup supply has the required volume of water available (UHS water level is within limits). The CST must be restored to OPERABLE status within 7 days. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup ESW supply. Additionally, verifying the backup water supply every 12 hours is adequate to ensure the backup water supply continues to be available. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks.

Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST contained water volume.

REFERENCES

1. FSAR, Section 9.2.6, Condensate Storage and Transfer System.
2. FSAR 10.4.9, Auxiliary Feedwater System.
3. FSAR 8.3A, Station Blackout.

BASES (continued)

REFERENCES	1.	FSAR, Section 9.2.2, Cooling System for Reactor Auxiliaries.
	2.	RFR 010060A

B 3.7 PLANT SYSTEMS

B 3.7.8 Essential Service Water (ESW) System

BASES

BACKGROUND

The ESW system provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the ESW system also provides this function for various safety related and nonsafety related components and receives coolant flow from the nonsafety related Service Water System. The safety related function is covered by this LCO.

The ESW system consists of two separate, 100% capacity, safety related, cooling water trains. Each train consists of a self cleaning strainer, prelube tank, one 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned, except in the unlikely event of a loss of coolant accident (LOCA). The pumps are automatically started upon receipt of a safety injection signal, low suction pressure to the auxiliary feedwater pumps coincident with an AFAS, or loss of offsite power. Upon receipt of one of these signals, the automatically actuated essential valves are aligned to their post accident positions as required. The ESW system also provides emergency makeup to the spent fuel pool and CCW System and is the backup water supply to the Auxiliary Feedwater System.

Additional information about the design and operation of the ESW system, along with a list of the components served, is presented in the FSAR, Section 9.2.1.2 (Ref. 1). The principal safety related function of the ESW system is the removal of decay heat from the reactor via the CCW System and removal of containment heat loads via the containment coolers.

APPLICABLE SAFETY ANALYSES

The design basis of the ESW system is for one ESW train, in conjunction with the CCW System and a 100% capacity containment cooling system, to remove accident generated and core decay heat following a design basis LOCA as discussed in the FSAR, Section 6.2 (Ref. 2). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the ECCS pumps. The ESW system is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown (which may include the use of local or remote indicators), that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves and relief valves. Additionally, vent and drain valves are not within the scope of this SR.

The 31 day Frequency is based on engineering judgment, and is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.8.2

This SR verifies proper automatic operation of the ESW system valves servicing safety related components or isolating the nonsafety related components on an actual or simulated actuation signal. These actuation signals include Loss of Power, SIS, and Low AFW Suction Pressure coincident with an AFAS. The ESW system is a standby emergency system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.3

This SR verifies proper automatic operation of the ESW system pumps on an actual or simulated actuation signal. These actuation signals include SIS, Low AFW Suction Pressure coincident with an AFAS, and Loss of Power. The ESW system is a standby emergency system that cannot be fully actuated as part of normal testing during normal operation. The 18 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. The ESW pump start on low AFW Suction Pressure Surveillance is performed under the conditions that apply during a unit outage and has the potential for an unplanned transient if the

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.8.3 (continued) Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.
REFERENCES	1. FSAR, Section 9.2.1, Essential Service Water System. 2. FSAR, Section 6.2, Containment Systems. 3. FSAR, Section 5.4.7, Residual Heat Removal System.

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

coolant accident, fission product release presented in the FSAR, Chapter 15A.3 (Ref. 2).

The worst case single active failure of a component of the CREVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

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

LCO

Two independent and redundant CREVS trains are required to be OPERABLE to ensure that at least one is available assuming a single failure disables the other train. Total system failure could result in exceeding a dose of 5 rem to the control room operator in the event of a large radioactive release.

The CREVS is considered OPERABLE when the individual components necessary to limit operator exposure are OPERABLE in both trains. A CREVS train is OPERABLE when the associated:

a. Control Room Air Conditioner, filtration and pressurization fans are OPERABLE;

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

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

In addition, the control room pressure boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

The LCO is modified by a Note allowing the control room boundary to be opened intermittently under administrative controls. 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 consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for control room isolation is indicated. Plant administrative controls address the breached pressure boundary.

Note that the Control Room Air Conditioning System (CRACS) forms a subsystem to the CREVS. The CREVS remains capable of performing its safety function provided the CRACS air flow path is intact and air circulation can be maintained. Isolation or breach of the CRACS air flow

(continued)

BASES

LCO (continued)

path can also render the CREVS flow path inoperable. In these situations, LCOs 3.7.10 and 3.7.11 may be applicable.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of irradiated fuel assemblies, CREVS must be OPERABLE to control operator exposure during and following a DBA.

In MODE 5 or 6, the CREVS is required to cope with the design basis release from the rupture of a waste gas tank.

During movement of irradiated fuel assemblies, the CREVS must be OPERABLE to cope with the release from a design basis fuel handling accident.

ACTIONS

A.1

When one CREVS train is inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the control room protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1

If the control room boundary is inoperable in MODE 1, 2, 3, and 4 such that neither CREVS train can establish the required positive pressure, action must be taken to restore an OPERABLE control room boundary within 24 hours. During the period that the control room boundary is inoperable, appropriate compensatory measures (consistent with the intent GDC 19) should be utilized to protect control room operators from potential hazards such as radioactive contamination, toxic chemicals, smoke, temperature and relative humidity, and physical security. Compensatory measures address entries into Condition B. See also the LCO Bases above. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, the availability of the CREVS to provide a filtered environment (albiet with potential control room inleakage), and the use of compensatory measures. The 24 hour Completion Time is a reasonable time to diagnose, plan, repair, and test most problems with the control room boundary.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CREVS train or control room boundary cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1.1, D.1.2, D.2.1, and D.2.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, if the inoperable CREVS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CREVS train in the CRVIS mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

Action D.1.2 requires the CREVS train placed in operation be capable of being powered by an emergency power source. This action assures OPERABILITY of the CREVS train in the unlikely event of a Fuel Handling Accident or Decay Tank rupture while shutdown concurrent with a loss of offsite power.

An alternative to Required Actions D.1.1.1 and D.1.2 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. Required Actions D.2.1 and D.2.2 would place the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1 and E.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CREVS trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

(continued)

BASES

ACTIONS (continued)

F.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable control room boundary (i.e., Condition B), the CREVS may not be capable of performing the intended function and the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once every month, by initiating from the control room, flow through the HEPA filters and charcoal adsorbers of both the filtration and pressurization systems, provides an adequate check of this system.

Monthly heater operations dry out any moisture accumulated in the charcoal from humidity in the ambient air. Each pressurization system train must be operated for ≥ 10 continuous hours with the heaters functioning. Functioning heaters will not necessarily have the heating elements energized continuously for 10 hours; but will cycle depending on the air temperature. Each filtration system train need only be operated for ≥ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy availability.

SR 3.7.10.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP).

The CREVS filter tests use the test procedure guidance in Regulatory Guide 1.52 (Ref. 3). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CREVS train starts and operates on an actual or simulated actuation signal. The actuation signal includes Control Room Ventilation Isolation or High Gaseous Radioactivity. The CREVS train automatically switches on an actual or simulated CRVIS signal into a

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.3 (continued)

CRVIS mode of operation with flow through the HEPA filters and charcoal adsorber banks. The Surveillance Requirement also verifies that a control room ventilation isolation signal (CRVIS) will be received by the LOCA sequencer to enable an automatic start of the Diesel Generator loads that are associated with a CRVIS. Verification that these loads will start and operate at the appropriate step in the LOCA sequencer and that other auto-start signals for these loads will be inhibited until the LOCA sequencer is reset is accomplished under Surveillance Requirement SR 3.8.1.12. The Frequency of 18 months is consistent with the typical operating cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.10.4

This SR verifies the integrity of the control room enclosure, and the assumed inleakage rates of the potentially contaminated air. The control room positive pressure, with respect to the outside atmosphere, is periodically tested to verify proper functioning of the CREVS. During the CRVIS mode of operation, the CREVS is designed to pressurize the control room $\geq$ 0.125 inches water gauge positive pressure with respect to the outside atmosphere in order to prevent unfiltered inleakage. The CREVS is designed to maintain this positive pressure with one train. The Frequency of 18 months on a STAGGERED TEST BASIS is consistent with the guidance provided in NUREG-0800 (Ref. 4).

REFERENCES

1. FSAR, Section 6.4, Habitability Systems.
2. FSAR, Chapter 15A.3, Control Room Radiological Consequences Calculation Models.
3. Regulatory Guide 1.52, Rev. 2, Design, Testing, and Maintenance Criteria for Atmospheric Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants.
4. NUREG-0800, Section 6.4, Rev. 2, July 1981, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.
5. Procedure EDP-ZZ-04107, HVAC Pressure Boundary and Watertight Door Control.

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Air Conditioning System (CRACS)

BASES

BACKGROUND

The CRACS provides temperature control for the control room.

The CRACS consists of two independent and redundant trains that provide cooling of recirculated control room air. Each train consists of a prefilter, self-contained refrigeration system (using essential service water as a heat sink), centrifugal fans, instrumentation, and controls to provide for control room temperature control. The CRACS is a subsystem to the CREVS, described in LCO 3.7.10, providing air temperature control for the control room.

The CRACS is an emergency system, which also operates during normal unit operations. A single train will provide the required temperature control to maintain the control room ≤ 84°F. The CRACS operation in maintaining the control room temperature is discussed in the FSAR, Section 9.4.1 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CRACS is to maintain the control room temperature for 30 days of continuous occupancy.

The CRACS components are arranged in redundant, safety related trains. During normal or emergency operations, the CRACS maintains the temperature ≤ 84°F. A single active failure of a component of the CRACS, with a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. The CRACS is designed in accordance with Seismic Category I requirements. The CRACS is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

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

LCO

Two independent and redundant trains of the CRACS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

all fuel rods in an assembly are damaged. The analysis of the LOCA assumes that radioactive materials leaked from the Emergency Core Cooling System (ECCS) and Containment Spray System during the recirculation mode are filtered and adsorbed by the Emergency Exhaust System. The DBA analysis of the fuel handling accident and of the LOCA assumes that only one train of the Emergency Exhaust System is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the one remaining train of this filtration system. The amount of fission products available for release from the fuel building is determined for a fuel handling accident and for a LOCA. These assumptions and the analysis follow the guidance provided in Regulatory Guides 1.4 (Ref. 6) and 1.25 (Ref. 5).

The Emergency Exhaust System satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

Two independent and redundant trains of the Emergency Exhaust System are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train, coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the auxiliary building or fuel building exceeding regulatory release limits in the event of a LOCA or fuel handling accident.

In MODES 1, 2, 3 and 4 the Emergency Exhaust System (EES) is considered OPERABLE when the individual components necessary to control releases from the auxiliary building are OPERABLE in both trains (i.e., the components required for the SIS mode of operation and the auxiliary building pressure boundary). During movement of irradiated fuel assemblies in the fuel building, the EES is considered OPERABLE when the individual components necessary to control releases from the fuel building are OPERABLE in both trains (i.e. the components required for the FBVIS mode of operation and the fuel building pressure boundary). An Emergency Exhaust System train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and

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

(continued)

BASES

LCO (continued)

The LCO is modified by a Note allowing the auxiliary or fuel building boundary to be opened intermittently under administrative controls. 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 consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for auxiliary or fuel building isolation is indicated. Plant administrative controls address the breached pressure boundary.

APPLICABILITY

In MODE 1, 2, 3, or 4, the Emergency Exhaust System is required to be OPERABLE to support the SIS mode of operation to provide fission product removal associated with ECCS leaks due to a LOCA and leakage from containment and annulus.

In MODE 5 or 6, the Emergency Exhaust System is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

During movement of irradiated fuel in the fuel building, the Emergency Exhaust System is required to be OPERABLE to support the FBVIS mode of operation to alleviate the consequences of a fuel handling accident.

The Applicability is modified by a Note. The Note clarifies the Applicability for the two safety-related modes of operation of the Emergency Exhaust System, i.e., the Safety Injection Signal (SIS) mode and the Fuel Building Ventilation Isolation Signal (FBVIS) mode. The SIS mode which aligns the system to the auxiliary building is applicable when the ECCS is required to be OPERABLE. In the FBVIS mode the system is aligned to the fuel building. This mode is applicable while handling irradiated fuel in the fuel building.

ACTIONS

A.1

With one Emergency Exhaust System train inoperable in MODE 1, 2, 3, or 4, action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the Emergency Exhaust System function. This condition only applies to the EES components required to support the SIS mode of operation. The 7 day Completion Time is based on the risk from an event occurring requiring the inoperable Emergency Exhaust System train, and the remaining Emergency Exhaust System train providing the required protection.

(continued)

BASES

ACTIONS (continued)

B.1

If the auxiliary building boundary is inoperable in MODE 1, 2, 3, and 4 such that neither EES train can establish the required negative pressure, action must be taken to restore an OPERABLE auxiliary building boundary within 24 hours. During the period that the auxiliary building boundary is inoperable, appropriate compensatory measures (consistent with the intent, as applicable, of GDC 19, 60, 61, 63, 64, and 10CFR Part 100) should be utilized to protect plant personnel from potential hazards such as radioactive contamination and physical security. Compensatory measures address entries into Condition B. See also the LCO Bases above. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, the availability of the EES to provide a filtered environment (albiet with potential auxiliary building exfiltration), and the use of compensatory measures. The 24 hour Completion Time is a reasonable time to diagnose, plan, repair, and test most problems with the auxiliary building boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, when Required Action A.1 or B.1 cannot be completed within the associated Completion Time, or when both Emergency Exhaust System trains are inoperable for reasons other than due to an inoperable auxiliary building boundary (i.e., Condition B), the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 3 within 6 hours, and in MODE 5 within 36 hours. This condition only applies to the EES components required to support the SIS mode of operation. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

With one Emergency Exhaust System train inoperable, during movement of irradiated fuel assemblies in the fuel building, the OPERABLE Emergency Exhaust System train must be started in the FBVIS mode immediately or fuel movement suspended. This action ensures that the remaining train is OPERABLE, that no undetected failures preventing system operation will occur, and that any active failure will be readily detected. This condition only applies to the EES components required to support the FBVIS mode of operation.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

If the system is not placed in operation, this action requires suspension of fuel movement, which precludes a fuel handling accident. This does not preclude the movement of fuel assemblies to a safe position.

E.1

When two trains of the Emergency Exhaust System are inoperable during movement of irradiated fuel assemblies in the fuel building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the fuel building. This does not preclude the movement of fuel to a safe position. This condition only applies to the EES components required to support the FBVIS mode of operation, including the fuel building pressure boundary.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month, by initiating from the Control Room flow through the HEPA filters and charcoal adsorbers, provides an adequate check on this system.

Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. Each Emergency Exhaust System train must be operated for ≥ 10 continuous hours with the heaters functioning. Functioning heaters would not necessarily have the heating elements energized continuously for 10 hours, but will cycle depending on the temperature. The 31 day Frequency is based on the known reliability of the equipment and the two train redundancy available. This SR can be satisfied with the EES in the SIS or FBVIS lineup during testing.

SR 3.7.13.2

This SR verifies that the required Emergency Exhaust System filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The Emergency Exhaust System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 7). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal. Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.3

This SR verifies that each Emergency Exhaust System train starts and operates on an actual or simulated actuation signals. These actuation signals include a Safety Injection Signal (applicable in MODE 1, 2, 3 and 4) and Spent Fuel Pool Gaseous Radioactivity Signal (applicable during movement of irradiated fuel in the fuel building). The 18 month Frequency is consistent with the typical operating cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

During emergency operations the Emergency Exhaust System will automatically start in either the SIS or FBVIS lineup depending on the initiating signal. In the SIS lineup, the fans operate with dampers aligned to exhaust from the Auxiliary Building and prevent unfiltered leakage. In the FBVIS lineup, which is initiated on a Spent Fuel Pool Gaseous Radioactivity - High Signal, the fans operate with the dampers aligned to exhaust from the Fuel Building to prevent unfiltered leakage. Normal exhaust air from the Fuel Building is continuously monitored by radiation detectors. One detector output will automatically align the Emergency Exhaust System in the FBVIS mode of operation. This surveillance requirement demonstrates that each Emergency Exhaust System train can be automatically started and properly configured to the FBVIS or SIS alignment, as applicable, upon receipt of an actual or simulated SIS signal and an FBVIS signal. It is not required that each Emergency Exhaust System train be started from both actuation signals during the same surveillance test provided each actuation signal is tested independently within the 18 month test frequency.

SR 3.7.13.4

This SR verifies the integrity of the auxiliary building enclosure. The ability of the auxiliary building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the Emergency Exhaust System. During the SIS mode of operation, the Emergency Exhaust System is designed to maintain a slight negative pressure in the auxiliary building, to prevent unfiltered leakage. The Emergency Exhaust System is designed to maintain a negative pressure $\geq$ 0.25 inches water gauge with respect to atmospheric pressure at the flow rate specified in the VFTP. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 7).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.13.5

This SR verifies the integrity of the fuel building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the Emergency Exhaust System. During the FBVIS mode of operation, the Emergency Exhaust System is designed to maintain a slight negative pressure in the fuel building, to prevent unfiltered leakage. The Emergency Exhaust System is designed to maintain a negative pressure ≥ 0.25 inches water gauge with respect to atmospheric pressure at the flow rate specified in the VFTP. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 7).

REFERENCES

1. FSAR, Section 6.5.1, Engineered Safety Features (ESF) Filter Systems.
2. FSAR, Section 9.4.2, Fuel Building HVAC.
3. FSAR, Section 9.4.3, Auxiliary Building HVAC.
4. FSAR, Section 15.7.4, Fuel Handling Accidents.
5. Regulatory Guide 1.25, Rev. 0, Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors.
6. Regulatory Guide 1.4, Rev. 2, Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident from Pressurized Water Reactors.
7. Regulatory Guide 1.52 (Rev. 2), Design, Testing and Maintenance Criteria for Atmospheric Cleanup System Air Filtration and Adsorption Units of Light Water Cooled Nuclear Power Plants.
8. NUREG-0800, Section 6.5.1, Rev. 2, July 1981, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.
9. Procedure EDP-ZZ-04107, HVAC Pressure Boundary and Watertight Door Control.

BASES (continued)

ACTIONS

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

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. An acceptable alternative is to verify by administrative means that the fuel storage pool verification has been performed since the last movement of fuel assemblies in the fuel storage pool. However, prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of pool water is expected to take place over such a short period of time.

REFERENCES

1. Callaway FSAR, Appendix 9.1A, "The High Density Rack (HDR) Design Concept."

2. Amendment No. 129 dated January 19, 1999 to the Callaway Operating License.

3. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

B 3.7 PLANT SYSTEMS

B 3.7.17 Spent Fuel Assembly Storage

BASES

BACKGROUND

The high density rack modules for the fuel storage pool are designed for storage of both new fuel and spent fuel. Spent fuel storage is designated into Regions based upon initial enrichment and accumulated burnup. Region 1 is designed to accommodate new fuel with a maximum nominal enrichment of 4.6 wt% U-235 with no burnable absorbers or up to 5.0 wt% U-235 with integral absorbers. Region 2 and Region 3 are designed to accommodate fuel of up to 5.0 wt% U-235 initial enrichments which have accumulated minimum burnups within the acceptable domain according to Figure 3.7.17-1, in the accompanying LCO.

Prior to storage of fuel assemblies in the fuel storage pool, overall pool storage configurations are prepared in accordance with administrative controls. The pool layouts include sufficient Region 1 storage to accommodate new and discharged fuel assemblies with low burnup. Fuel storage utilizes either a Mixed Zone Three Region configuration and/or a checkerboarding configuration. A combination of the Mixed Zone Three Region (MZTR) configuration and checkerboard pattern within the same rack is not allowed.

In a Mixed Zone Three Region configuration, Region 1 storage cells are only located along the outside periphery of the rack modules and must be separated by one or more Region 2 storage cells. Region 1 storage cells may be located directly across from one another when separated by a water gap. The outer rows of alternating Region 1 and 2 storage cells must be further separated from the internal Region 3 storage cells by one or more Region 2 storage cells.

In the checkerboarding configuration, fuel assemblies are placed in an alternating checkerboard style pattern with empty storage cells (i.e., fuel assemblies are surrounded on all four sides by empty storage cells except at the checkerboard boundary). Region 1 fuel assemblies may not be located directly across from one another, even when separated by a water gap. This arrangement may be used anywhere in the fuel storage area if the checkerboarding pattern is maintained in a linear array equal to or greater than 2 x 2. A checkerboard area may be bounded by either a water gap, empty cells, Region 2 fuel assemblies or Region 3 fuel assemblies.

The water in the fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost,

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single DG.

Offsite power is supplied to the unit switchyard from the transmission network by three transmission lines. From the switchyard, two electrically and physically separated circuits provide AC power, through ESF transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the FSAR, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, voltage regulation equipment, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF buses.

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs NE01 and NE02 are dedicated to ESF buses NB01 and NB02, respectively. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure, steam line pressure or high containment pressure signals) or on an ESF bus undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus

(continued)

BASES

BACKGROUND (continued)

undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a Load Shedder and Emergency Load Sequencer (LSELS) strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the LSELS. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 6201 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the unit.

In addition, one required LSELS per train must be OPERABLE.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

One offsite circuit consists of either Safeguards Transformer A orB, which is supplied from Switchyard Bus A or B, and feeds through a breaker to ESF transformer XNB01, which, in turn, powers the NB01 ESF bus through its normal feeder breaker or NB02 ESF bus through its alternate feeder breaker, if needed. Another offsite circuit consists of the Startup Transformer, which is normally fed from the Switchyard feeding through breaker PA 0201, to ESF transformer XNB02, which, in turn, powers NB02 ESF bus through its normal feeder breaker and NB01 through its alternate feeder breaker, if needed. Voltage regulation equipment consisting of automatic load tap changing ESF transformers and associated capacitor banks maintain the preferred sources in the event of changing switchyard voltage.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 12 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

(continued)

BASES

LCO (continued)

Initiating a DG start upon a detected undervoltage condition, tripping of the incoming offsite power upon a detected undervoltage or degraded voltage condition, shedding of nonessential loads, and proper sequencing of loads are required functions of LSELS and required for DG OPERABILITY. OPERABILITY of the undervoltage and degraded voltage instrumentation functions is addressed in LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus provided the appropriate LCO Required Actions are entered for loss of one offsite power source.

APPLICABILITY

The AC sources LSELS trains are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if the second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

(continued)

BASES

ACTIONS (continued)

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps and the turbine driven auxiliary feedwater pump which must be available for mitigation of a feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included in this condition.

A Note is added to this Required Action stating that in MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. The reason for the Note is to confirm the OPERABILITY of the turbine driven auxiliary feedwater pump in this Condition, since the auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action A.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train has no offsite power supplying its loads; and

b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable coincident with no offsite power to one train of the onsite Class IE Electrical Power Distribution System, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

Required Action A.2 is no longer applicable when the train of onsite Class IE Electrical Power Distribution System is connected to the

(continued)

BASES

ACTIONS

A.2 (continued)

remaining OPERABLE offsite circuit. In this case, Required Actions A.1 and A.3 continue to apply.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

BASES

ACTIONS

A.1 (continued)

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps and the turbine-driven auxiliary feedwater pump which must be available for mitigation of a feedwater line break. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

A Note is added to this Required Action stating that in MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. The reason for the Note is to confirm the OPERABILITY of the turbine driven auxiliary feedwater pump in this Condition, since the auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

(continued)

BASES

ACTIONS

B.2 (continued)

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG. SR 3.8.1.2 does not have to be performed. If the DG was declared inoperable for preplanned preventive maintenance, testing, or maintenance to correct a condition which, if left uncorrected, would not affect the OPERABILITY of the DG, or for an inoperable Support System, or for an independently testable component, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG. Required Action B.3.2 is modified by a Note

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

stating that it is satisfied by the automatic start and sequence loading of the DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will

(continued)

BASES

ACTIONS

B.4 (continued)

result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps and the turbine driven auxiliary feedwater pump which must be available for mitigation of a feedwater line break. Single train features, other than the turbine driven auxiliary feedwater pump, are not included in this Condition.

A Note is added to this Required Action stating that in MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. The reason for the Note is to confirm the OPERABILITY of the turbine driven auxiliary feedwater pump in this Condition, since the auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems- Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted.

The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). The fuel handling accident (in containment) analyzed in Reference 2 consists of dropping a single irradiated fuel assembly onto other irradiated fuel assemblies. The requirements of LCO 3.9.7, "Refueling Pool Water Level," and the minimum decay time of 100 hours prior to CORE ALTERATIONS ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 3), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 100 values.

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge penetrations and the personnel air lock. For the OPERABLE containment purge penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge Isolation System to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit. For the containment personnel air lock, one air lock door must be capable of being closed. Both containment personnel air lock doors may be open during movement of irradiated fuel or CORE ALTERATIONS, provided an air lock door is capable of being closed. Administrative controls ensure that 1) appropriate personnel are aware that both personnel air lock doors are open, 2) a specified individual(s) is designated and available to close the air lock following a required evacuation of containment, and 3) any obstruction(s) (e.g. cables and hoses) that could prevent closure of an open air lock can be quickly removed (Ref. 1).

The LCO is modified by a NOTE allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and

(continued)

BASES

LCO (continued)

2) specified individuals are designated and readily available to isolate the flow path in the event of a fuel handling accident (Ref. 4).

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. Proper installation and removal of the upper internals with irradiated fuel in the reactor vessel does not constitute a CORE ALTERATION or a movement of irradiated fuel. Therefore, this LCO is not applicable during installation and removal of the reactor vessel upper internals.

In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1, "Containment." In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Purge Isolation System not capable of automatic actuation when the isolation valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge isolation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge isolation signal.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1 (continued)

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the outside atmosphere.

SR 3.9.4.2

This Surveillance demonstrates that each containment purge isolation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. The 18 month Frequency maintains consistency with other similar ESFAS instrumentation and valve testing requirements. In LCO 3.3.6, the Containment Purge Isolation instrumentation requires a CHANNEL CHECK every 12 hours, an ACTUATION LOGIC TEST every 31 days on a STAGGERED TESTS BASIS, and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 18 months a TADOT and a CHANNEL CALIBRATION are performed. The system actuation response time is demonstrated every 18 months on a STAGGERED TEST BASIS. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These Surveillances will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

REFERENCES

1. Amendment 114 to Facility Operating License No. NPF-30, Callaway Unit 1, dated July 15, 1996.

2. FSAR, Section 15.7.4.

3. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.

4. Amendment 138 to Facility Operating License No. NPF-30, Callaway Unit 1, dated September 26, 2000.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the plate out of boron would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

The RHR System is retained as a Specification because it meets Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

(continued)

BASES

LCO (continued)

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the RCS temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling pool.

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.7, "Refueling Pool Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level." Additional RHR loop requirements in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange are located in FSAR 16.1.2.1, "Flow Path-Shutdown Limiting Condition For Operation."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

(continued)

BASES

ACTIONS (continued)

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS because all unborated water sources are isolated and administrative controls are placed on refueling decontamination activities (See Bases for LCO 3.9.1).

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling pool water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition. Performance of Required Action A.2 shall not preclude completion of movement of a component to a safe condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

(continued)

BASES

LCO (continued)

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the RCS temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. An OPERABLE RHR loop must be capable of being realigned to provide an OPERABLE flow path.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level." Additional RHR loop requirements in MODE 6 with the water level ≥ 23 feet above the top of the reactor vessel flange are located in FSAR 16.1.2.1, "Flow Path-Shutdown Limiting Condition For Operation."

The Applicability is modified by a Note stating that entry into a MODE or other specified condition in the Applicability is not permitted while the LCO is not met. This note specifies an exception to LCO 3.0.4 and would prevent the transition into MODE 6 with less than 23 feet of water above the top of the vessel flange while the RHR function was degraded.

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and restored to operation in accordance with the LCO or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS, because all of the

(continued)

BASES

ACTIONS

B.1 (continued)

unborated water sources are isolated and administrative controls are placed on refueling decontamination activities (See Bases for LCO 3.9.1).

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable at water levels above reduced inventory, based on the low probability of the coolant boiling in that time. At reduced inventory conditions, additional actions are taken to provide containment closure in a reduced period of time (Reference 2). Reduced inventory is defined as RCS level lower than 3 feet below the reactor vessel flange.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.6.2

Verification that the required pump is OPERABLE ensures that an additional RHR pump can be placed in operation, if needed, to maintain

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.2 (continued)

decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR, Section 5.4.7.
2. Generic Letter No. 88-17, "Loss of Decay Heat Removal."

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Pool Water Level

BASES

BACKGROUND	The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the fuel transfer canal, refueling pool and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3 and acceptance in Reference 6.
APPLICABLE SAFETY ANALYSES	During movement of irradiated fuel assemblies, the water level in the refueling pool is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.25 (Ref. 1). The reactor is assumed to have been subcritical for 100 hours prior to movement of irradiated fuel in the reactor vessel. A minimum water level of 23 ft (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of the damaged rods is retained by the refueling pool water. In addition, for the analyses for the accident in the reactor building, the dropped assembly is assumed to damage 20% of the rods of a different assembly. The fission product release point is assumed to be at the point of impact at the top of the reactor vessel flange. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1). The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained well within the limits of 10 CFR 100 (Refs. 4, 5, and 6). Refueling pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)