WOLF CREEK
NUCLEAR OPERATING CORPORATION

Kevin J. Moles
Manager Regulatory Affairs

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

Subject: Docket No. 50-482: Wolf Creek Generating Station Changes to Technical Specification Bases – Revisions 24 through 31

Gentlemen:

The Wolf Creek Generating Station (WCGS) Unit 1 Technical Specifications (TS), Section 5.5.14, "Technical Specifications (TS) Bases Control Program," provide the means for making changes to the Bases without prior NRC approval. In addition, TS Section 5.5.14 requires that changes made without NRC approval be provided to the NRC on a frequency consistent with 10 CFR 50.71(e). The Enclosure provides those changes made to the WCGS TS Bases (Revisions 24 through 31) under the provisions of TS Section 5.5.14 and a List of Effective Pages. This submittal reflects changes from January 1, 2006 through December 31, 2006.

This letter contains no commitments. If you have any questions concerning this matter, please contact me at (620) 364-4126, or Diane Hooper at (620) 364-4041.

Sincerely,

Kevin J. Moles

KJM/rlt

Enclosure

cc: J. N. Donohew (NRC), w/e
V. G. Gaddy (NRC), w/e
B. S. Mallett (NRC), w/e
Senior Resident Inspector (NRC), w/e

A001

Wolf Creek Generating Station

Changes to the Technical Specification Bases

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BASES

SURVEILLANCE REQUIREMENTS (continued)

power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in a reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ are made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that they are verified within 24 hours from when equilibrium conditions are achieved at RTP (or any other level for extended operation). Equilibrium conditions are achieved when the core is sufficiently stable at the intended operating conditions to perform flux mapping. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q^C(Z) = F_Q^M(Z)\ (1.0815)$ (Ref. 4). $F_Q^C(Z)$ is then compared to its specified limits.

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

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

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required within 24 hours after achieving equilibrium conditions at this higher power level

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SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

(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) are provided 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 amount of the axial core region that can be excluded during the performance of SR 3.2.1.2 shall not exceed 15% of the upper and lower core regions, and may be reduced on a cycle-specific basis as determined during the core reload design process. The amount of the axial core region that can be excluded during the performance of SR 3.2.1.2 is identified in the COLR. The axial core regions 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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

a precise measurement in these regions. It should be noted that while the transient $F_Q(Z)$ limits are not measured in these axial core regions, the analytical transient $F_Q(Z)$ limits in these axial core regions are demonstrated to be satisfied during the core reload design process.

This Surveillance has been modified by a Note that may require 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 ensures 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.

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REFERENCES

1. 10 CFR 50.46, 1974.
2. USAR, Section 15.4.8.
3. 10 CFR 50, Appendix A, GDC 26.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties," June 1988.
5. Performance Improvement Request 2005-3311.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux - High (continued)

levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux - High channels to be OPERABLE. The Trip Setpoint is ≤ 109% RTP.

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

b. Power Range Neutron Flux - Low

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

The LCO requires all four of the Power Range Neutron Flux - Low channels to be OPERABLE. The Trip Setpoint is ≤ 25% RTP.

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

BASES

APPLICABLE SAFTY ANALYSES, LCO, and APPLICABILITY

b. Power Range Neutron Flux - Low (continued)

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

3. Power Range Neutron Flux Rate

The Power Range Neutron Flux Rate trips use the same channels as discussed for Function 2 above.

a. Power Range Neutron Flux - High Positive Rate

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

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

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

b. Power Range Neutron Flux - High Negative Rate

The Power Range Neutron Flux - High Negative Rate trip Function ensures that protection is provided for multiple rod drop accidents. At high power levels, a multiple rod drop accident could cause local flux peaking that would

BASES

ACTIONS (continued)

P.1 and P.2

Condition P applies to Turbine Trip on Turbine Stop Valve Closure. With one or more channel(s) inoperable, the inoperable channel(s) must be placed in the trip condition within 72 hours. For the Turbine Trip on Turbine Stop Valve Closure function, four of four channels are required to initiate a reactor trip; hence, more than one channel may be placed in trip. If the channel(s) cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel(s) in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 12 and Reference 14.

Q.1 and Q.2

Condition Q applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status (Required Action Q.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action Q.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable train to OPERABLE status is justified in Reference 12. The Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions are not required when a logic train is being tested under the 4-hour bypass Note of Condition Q). Entry into Condition Q is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition Q is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition Q entry. If this situation were to occur during the 24-hour Completion Time of Required Action Q.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition Q or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

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ACTIONS

Q.1 and Q.2 (continued)

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

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

- Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The 24-hour Completion Time is justified in Reference 13. The shutdown Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. Placing the unit in MODE 3 results in Condition C entry if one RTB train is inoperable and the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

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REFERENCES (continued)

12. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

13. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

14. WOG-06-17, "WCAP-10271-P-A Justification for Bypass Test Time and Completion Time Technical Specification Changes for Reactor Trip on Turbine Trip (ITSWG Action item #314)," January 20, 2006.

TABLE B 3.3.1-1
(Page 1 of 2)

FUNCTION	TRIP SETPOINT[(a)]
1. Manual Reactor Trip	NA
2. Power Range Neutron Flux	
a. High	≤ 109% of RTP
b. Low	≤ 25% of RTP
3. Power Range Neutron Flux	
a. High Positive Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
b. High Negative Rate	≤ 4% of RTP with a time constant ≥ 2 seconds
4. Intermediate Range Neutron Flux	≤ 25% of RTP
5. Source Range Neutron Flux	≤ 10^5 cps
6. Overtemperature ΔT	See Table 3.3.1-1 Note 1
7. Overpower ΔT	See Table 3.3.1-1 Note 2
8. Pressurizer Pressure	
a. Low	≥ 1940 psig
b. High	≤ 2385 psig
9. Pressurizer Water level - High	≤ 92% of instrument span
10. Reactor Coolant Flow - Low	≥ 89.9% of loop design flow (90,324 gpm)
11. Not Used	
12. Undervoltage RCPs	≥ 10578 Vac
13. Underfrequency RCPs	≥ 57.2 Hz
14. Steam Generator (SG) Water Level Low - Low	≥ 23.5% of narrow range instrument span
15. Not Used	
16. Turbine Trip	
a. Low Fluid Oil Pressure	≥ 590.00 psig
b. Turbine Stop Valve Closure	≥ 1% open

TABLE B 3.3.1-1
(Page 2 of 2)

FUNCTION	TRIP SETPOINT[a]
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	N.A.
18. Reactor Trip System Interlocks	
a. Intermediate Range Neutron Flux, P-6	≥ 1.0E-10 amps
b. Low Power Reactor Trips Block, P-7	N.A.
c. Power Range Neutron Flux, P-8	≤ 48% RTP
d. Power Range Neutron Flux, P-9	≤ 50% RTP
e. Power Range Neutron Flux, P-10	10% RTP
f. Turbine Impulse Pressure, P-13	≤ 10% turbine power
19. Reactor Trip Breakers	N.A.
20. Reactor Trip breaker Undervoltage and Shunt Trip Mechanisms	N.A.
21. Automatic Trip Logic	N.A.

[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. This also applies to the Overtemperature ΔT and Overpower ΔT K and τ values.

TABLE B 3.3.1-2
(Page 1 of 2)

	FUNCTIONAL UNIT	RESPONSE TIME
1.	Manual Reactor Trip	N.A.
2.	Power Range Neutron Flux	
	a. High	≤ 0.5 second[(1)]
	b. Low	≤ 0.5 second[(1)]
3.	Power Range Neutron Flux	
	a. High Positive Rate	≤ 0.5 second[(1)].
	b. High Negative Rate	≤ 0.5 second[(1)]
4.	Intermediate Range Neutron Flux	N.A.
5.	Source Range Neutron Flux	N.A.
6.	Overtemperature ΔT	≤ 6.0 seconds[(1)]
7.	Overpower ΔT	≤ 6.0 seconds[(1)]
8.	Pressurizer Pressure	
	a. Low	≤ 2.0 seconds
	b. High	≤ 2.0 seconds
9.	Pressurizer Water Level - High	N.A.
10.	Reactor Coolant Flow - Low	
	a. Single Loop (Above P-8)	≤ 1.0 second
	b. Two Loops (Above P-7 and below P-8)	≤ 1.0 second
11.	Not Used	
12.	Undervoltage - Reactor Coolant Pumps	≤ 1.5 seconds
13.	Underfrequency - Reactor Coolant Pumps	≤ 0.6 second
14.	Steam Generator Water Level - Low-Low	≤ 2.0 seconds
15.	Not Used	

[(1)] Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

BASES

ACTIONS (continued)

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

Condition F applies to:

- Manual Initiation of Steam Line (fast close) Isolation; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. 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.

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

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

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12 and Reference 15. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. 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.

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ACTIONS

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

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform train surveillance.

Consistent with the requirement in Reference 12 to include Tier 2 insights into the decision-making process before taking equipment out of service, restrictions on concurrent removal of certain equipment when a logic train is inoperable for maintenance are included (note that these restrictions are not required when a logic train is being tested under the 4-hour bypass Note of Condition G). Entry into Condition G is not a typical, pre-planned evolution during power operation, other than for surveillance testing. Since Condition G is typically entered due to equipment failure, it follows that some of the following restrictions may not be met at the time of Condition G entry. If this situation were to occur during the 24-hour Completion Time of Required Action G.1, the Configuration Risk Management Program will assess the emergent condition and direct activities to restore the inoperable logic train and exit Condition G or fully implement these restrictions or perform a plant shutdown, as appropriate from a risk management perspective. The following restrictions will be observed:

- To preserve ATWS mitigation capability, activities that degrade the availability of the auxiliary feedwater system, RCS pressure relief system (pressurizer PORVs and safety valves), AMSAC, or turbine trip should not be scheduled when a logic train is inoperable for maintenance.

- To preserve LOCA mitigation capability, one complete ECCS train that can be actuated automatically must be maintained when a logic train is inoperable for maintenance.

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

Activities on electrical systems (e.g., AC and DC power) and cooling systems (e.g., essential service water and component cooling water) that support the systems or functions listed in the first three bullets should not be scheduled when a logic train is inoperable for maintenance. That is, one complete train of a function that supports a complete train of a function noted above must be available.

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H.1 and H.2

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

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours. The 24 hours allowed for restoring the inoperable train to OPERABLE status is justified in Reference 12 and Reference 15. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform train surveillance.

I.1 and I.2

Condition I applies to:

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

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-three logic will result in actuation. The 72 hour Completion Time is justified in Reference 12. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the unit to be placed in MODE 3 within the following 6 hours.

BASES

ACTIONS

I.1 and I.2 (continued)

The allowed Completion Time of Required Action I.2 is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 12 hours for surveillance testing of other channels. The 72 hours allowed to place the inoperable channel in the tripped condition, and the 12 hours allowed for a second channel to be in the bypassed condition for testing, are justified in Reference 12.

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 allowing automatic start of the AFW System pumps. If a channel is inoperable, 1 hour is allowed to place the channel 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.

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

Condition K applies to the RWST Level - Low Low Coincident with Safety Injection Function.

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

BASES

REFERENCES (continued)

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

10. "Wolf Creek Setpoint Methodology Report," SNP (KG)-492, August 29, 1984.

11. Amendment No. 43 to Facility Operating License No. NPF-42, March 29, 1991.

12. WCAP-14333-P-A, Revision 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.

13. WCAP-15376-P-A, Revision 1, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," March 2003.

14. 10 CFR 50.55a(b)(3)(iii), Code Case OMN-1.

15. Performance Improvement Request (PRI) 2005-2067.

TABLE B 3.3.2-1
(Page 1 of 2)

FUNCTION	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	≥ 1830 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)
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. Containment Pressure - High-2	≤ 17.0 psig
d. Steam Line Pressure	
(1) Low	≥ 615 psig
(2) Negative Rate - High	≤ 100 psi

BASES

ACTIONS

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

Alternatively, both trains may be place in the FBVIS mode within 1 hour. This ensures the EES function is performed even in the presence of a single failure.

D.1

Condition D applies when the Required Action and associated Completion Time for Conditions A, B, or C have not been met and irradiated fuel assemblies are being moved in the fuel building. Movement of irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require EES actuation. This does not preclude movement of a fuel assembly to a safe position.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which EES Actuation Functions.

SR 3.3.8.1

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.

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

The 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the EES actuation. The setpoints shall be left consistent with the unit specific calibration procedure tolerance. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience.

SR 3.3.8.3

SR 3.3.8.3 is the performance of an ACTUATION LOGIC TEST using the BOP ESFAS automatic tester. The actuation logic is tested every 31 days on a STAGGERED TEST BASIS. All possible logic combinations, with and without applicable permissive, are tested for each protection function. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience. The SR is modified by a Note stating that the continuity check may be excluded. This SR is applied to the balance of plant actuation logic and relays that do not have circuits installed to perform the continuity check.

SR 3.3.8.4

SR 3.3.8.4 is the performance of a TADOT. This test is a check of the manual actuation functions and is performed every 18 months. Each manual actuation function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (e.g., pump starts, valve cycles, etc.). The Frequency is based on operating experience and is consistent with the typical industry refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

All of the accident/safety analyses performed at full rated thermal power assume that all four RCS loops are in operation as an initial condition.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Some accident/safety analyses have been performed at zero power conditions assuming only two RCS loops are in operation to conservatively bound lower modes of operation. The events which assume only two RCPs in operation include the uncontrolled RCCA Bank withdrawal from subcritical event and the hot zero power rod ejection events. While all accident/safety analyses performed at full rated thermal power assume that all the RCS loops are in operation, selected events examine the effects resulting from a loss of RCP operation. These include the complete and partial loss of forced RCS flow, RCP locked rotor, and RCP shaft break events. For each of these events, it is demonstrated that all the applicable safety criteria are satisfied. For the remaining accident/safety analyses, operation of all four RCS loops during the transient up to the time of reactor trip is assumed thereby ensuring that all the applicable acceptance criteria are satisfied. Those transients analyzed beyond the time of reactor trip were examined assuming that a loss of offsite power occurs which results in the RCPs coasting down.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the limit values, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP and an OPERABLE SG. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow.

APPLICABILITY

In MODES 1 and 2, the reactor when critical has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

BASES

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 368°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

BASES

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance without the redundant nonoperating loop, is justified because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If the required RCS loop is not in operation, and the Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to place the Rod Control System in a condition incapable of rod withdrawal (e.g., by de-energizing all CRDMs, by opening the RTBs or de-energizing the motor generator (MG) sets). When the Rod Control System is capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the Rod Control System must be rendered incapable of rod withdrawal. The Completion Time of 1 hour to restore the required RCS loop to operation or defeat the Rod Control System is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

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

If four RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, place the Rod Control System in a condition incapable of rod withdrawal (e.g., by

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event.

The operation of one RCP in MODES 3, 4, and 5 provides adequate flow to ensure mixing, prevent stratification, and produce gradual reactivity changes during RCS boron concentration reductions. With no reactor coolant loop in operation in either MODES 3, 4, or 5, dilution sources must be isolated and administratively controlled. The boron dilution analysis in these MODES take credit for the mixing volume associated with having at least one reactor coolant loop in operation (Ref. 1).

RCS Loops - MODE 4 satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the necessary testing, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 368°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop is comprised of an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

BASES

LCO (continued)

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with any RCS cold leg temperature ≤ 368°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required. A SG can perform as a heat sink via natural circulation when it has an adequate water level and is OPERABLE.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side wide range water level of at least two SGs is required to be ≥ 66%.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and

BASES

APPLICABILITY (continued)

LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side wide range water levels < 66%, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing. Suspending the introduction into the RCS, coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading. Valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can allow varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address RCS operational LEAKAGE. However, the other forms of operational LEAKAGE are related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analyses for events resulting in steam discharge to the atmosphere assume that primary to secondary LEAKAGE from all steam generators (SGs) is one gallon per minute or increases to one gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. Other accidents or transients involving secondary steam release to the atmosphere, include the steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The USAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via atmospheric relief valves.

The safety analysis for the SLB accident assumes the entire 1 gpm primary to secondary LEAKAGE is through the affected generator as an initial condition. The dose consequences resulting from the SLB and SGTR accidents are well within the limits defined in 10 CFR 100 (Ref. 5) (i.e., a small fraction of these limits).

The safety analysis for RCS main loop piping for GDC-4 (Ref. 1) assumes 1 gpm unidentified leakage and monitoring per Regulatory Guide 1.45 (Ref. 2) are maintained (Ref. 4).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

BASES

LCO (continued)

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE Through Any One SG

The limit of 150 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, "Steam Generator Program Guidelines," (Ref. 6). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational LEAKAGE rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCS operational LEAKAGE is greatest when the RCS is pressurized.

BASES

APPLICABILITY (continued)

In MODES 5 and 6, RCS operational LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists or primary to secondary LEAKAGE is not within limit, or if unidentified or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS operational LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions (stable temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modified by two Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is preferred when performing a proper inventory balance since calculations during non-steady state conditions must account for the changing parameters. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows. An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. When non-steady state operation precludes surveillance performance, the surveillance should be performed in accordance with the Note, provided greater than 72 hours have elapsed since the last performance.

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.2 (continued)

secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 7. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 7).

REFERENCES

1. 10 CFR 50, Appendix A, GDC 4 and 30.
2. Regulatory Guide 1.45, May 1973.
3. USAR, Section 15.6.3.
4. NUREG-1061, Volume 3, November 1984.
5. 10 CFR 100.
6. NEI 97-06, "Steam Generator Guidelines."
7. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump (Ref. 2). The Containment Sump Level and Flow Monitoring System used to collect unidentified LEAKAGE and Containment Cooler Condensate Monitoring System are instrumented to alarm for increases of 0.5 to 1.0 gpm in the normal flow rates. The instrumentation provided is such that over a period of time (1 hour or more), the collected flow rate can be determined with an accuracy of better than 1.0 gpm (Ref. 3). This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring are practical for this leakage detection system. Radioactivity detection systems (GT RE-31 or GT RE-32) are included for monitoring particulate activity because of their sensitivities and rapid responses to RCS LEAKAGE.

The measurement of containment atmosphere gaseous radioactivity is less sensitive than the measurement of particulate radioactivity for the purpose of detecting RCS leakage. Evaluations have shown that the pre-existing containment radioactive gaseous background levels for which reliable detection is possible is dependent upon the reactor power level, percent failed fuel in the reactor, and air volume exchange brought about by the containment purge system. With primary coolant radionuclide

BASES

BACKGROUND (continued)

concentrations less than equilibrium levels, such as during startup and operation with no fuel defects, the increase in detector count rate due to leakage will be partially masked by 1) the statistical variation of the minimum detector background count rate, and 2) the Ar-41 activation activity rendering reliable detection of a 1 gpm leak uncertain. The containment gaseous radioactivity monitor is considered most useful for detecting an RCS-to-containment atmosphere leak if elevated reactor coolant gaseous activity is present. The containment gaseous radioactivity monitors are not required by this LCO. (Reference 9)

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from air coolers. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The asymmetric loads produced by postulated breaks are the result of assumed pressure imbalance, both internal and external to the RCS. The internal asymmetric loads result from a rapid decompression that causes large transient pressure differentials across the core barrel and fuel assemblies. The external asymmetric loads result from the rapid depressurization of the annulus regions, such as the annulus between the reactor vessel and the shield wall, and cause large transient pressure differentials to act on the vessel. These differential pressure loads could

BASES

APPLICABLE SAFETY ANALYSES (continued)

damage RCS supports, core cooling equipment or core internals. This concern was first identified as Multiplant Action (MPA) D-10 and subsequently as Unresolved Safety Issue (USI) A-2, "Asymmetric LOCA Loads." This issue was discussed in Reference 4.

The resolution of USI A-2 for Westinghouse PWRs was the use of fracture mechanics technology for RCS piping > 10 inches diameter (Ref. 5). This technology became known as leak-before-break (LBB). Included within the LBB methodology was the requirement to have leak detection systems capable of detecting a 1.0 gpm leak within four hours. This leakage rate is designed to ensure that adequate margins exist to detect leaks in a timely manner during normal operating conditions.

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the USAR (Ref. 3). Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak occur detrimental to the safety of the unit and the public.

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the Containment Sump Level and Flow Monitoring System, one containment atmosphere particulate radioactivity monitor and the Containment Cooler Condensate Flow Monitoring System provide an acceptable minimum.

BASES

LCO (continued)

For containment atmosphere particulate radioactivity monitor instrumentation, OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY also requires correct valve lineups, sample pump operation, sample line insulation and heat tracing, as well as detector OPERABILITY, since these supporting features are necessary for the monitors to rapidly detect RCS LEAKAGE.

The Containment Cooler Condensate Flow Monitoring System is considered OPERABLE when it is capable of measuring liquid flow from the containment coolers. An OPERABLE Containment Cooler Condensate Flow Monitoring System consists of a containment cooler drain collection header, a vertical standpipe, valving, and standpipe level indication for each cooler. Additionally, the plant process computer must be capable of calculating the leakage rate indicated by the condensate being collected. At least two containment coolers must be operating for the Containment Cooler Condensate Flow Monitoring System to be OPERABLE (Ref. 6).

Each containment cooler's air inlet temperature, relative humidity and dewpoint determines the amount of condensate the cooler will produce. Historically, the "D" containment cooler has produced the least amount of condensate. A containment cooler that is producing a small amount of condensate may result in a stable standpipe level and infrequent actuation of the automatic dump valve. Indications that the automatic dump valve may not be operating properly are no level indication in the standpipe or overfilling of the containment cooling drip pan (Ref. 7).

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is required to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

A.1 and A.2

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 measurement of low leakage by monitoring level increase versus time.

BASES

ACTIONS

A.1 and A.2 (continued)

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 level, 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 Containment 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, B.2.1 and B.2.2

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 for particulate radioactivity or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Alternatively, continued operation is allowed if the containment air cooler condensate monitoring system is OPERABLE, provided grab samples are taken or water inventory balances are performed every 24 hours.
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 level, 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.

BASES

ACTIONS (continued)

C.1 and C.2

With the required containment cooler condensate monitoring system inoperable, alternative action is again required. Either SR 3.4.15.1 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of the containment cooler condensate monitoring system to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS 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 level, 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.

D.1 and D.2

With the required containment atmosphere particulate radioactivity monitor and the required Containment Cooler Condensate Monitoring System inoperable, the means of detecting leakage is the Containment Sump Level and Flow Monitoring System. This Condition does not provide all the required diverse means of leakage detection. The 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.

Refer to LCO 3.3.6, "Containment Purge Isolation Instrumentation," upon a loss of the required containment atmosphere radioactivity monitor to ensure LCO requirements are met.

E.1 and E.2

If a Required Action of Condition A, B, C or D cannot be met, 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 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

F.1

With all required monitoring methods inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere particulate radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere particulate radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3, SR 3.4.15.4, and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is atypical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. Regulatory Guide 1.45.
3. USAR, Section 5.2.5.
4. NUREG-609, "Asymmetric Blowdown Loads on PWR Primary Systems," 1981.

BASES

REFERENCES (continued)

5. Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops."

6. USAR, Section 6.2.2.2.2.

7. Performance Improvement Request 2005-2823.

8. Performance Improvement Request 2006-000102.

9. NRC letter, "Wolf Creek Generating Station – License Amendment Request to Change the Reactor Coolant System Leakage Detection Instrumentation Methodology (TAC No. MC8214)," May 16, 2006.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the exclusion area boundary can receive for 2 hours following an accident, or at the low population zone outer boundary for the radiological release duration, is specified in 10 CFR 100.11 (Ref. 1). Doses to control room operators must be limited per GDC 19. The limits on specific activity ensure that the offsite and control room doses are appropriately limited during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the dose consequences in the event of a steam line break (SLB) or steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133. The allowable levels are intended to ensure that offsite and control room doses meet the appropriate acceptance criteria in the Standard Review Plan (Ref. 2).

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite and control room doses meet the appropriate Standard Review Plan acceptance criteria following a SLB or SGTR accident. The safety analyses (Refs. 3 and 4) assume the specific activity of the reactor coolant is at or more conservative than the LCO limits, and an existing reactor coolant steam generator (SG) tube leakage rate of 1 gpm exists. The safety analyses assume the specific activity of the secondary coolant is at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.18, "Secondary Specific Activity."

The analysis for the SLB and SGTR accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The analyses consider two cases of reactor coolant specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases, by a factor of 500, the rate of release of iodine from the fuel rods containing cladding defects to the primary coolant immediately after a SLB or SGTR, respectively. The second case assumes the initial reactor coolant iodine activity at

BASES

APPLICABLE SAFETY ANALYSES (continued)

60 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas specific activity is assumed to be equal to or greater than 500 μCi/gm DOSE EQUIVALENT XE-133.

The SGTR analysis also assumes a loss of offsite power at the same time as the reactor trip. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal in the analysis of an SGTR with a failed atmospheric relief valve on the faulted steam generator. In the analysis of an SGTR with a failed AFW flow control valve on the faulted steam generator, reactor trip and safety injection are assumed to occur at the time of the tube rupture to maximize the potential for overfilling the ruptured steam generator.

The loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG atmospheric relief valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the Residual Heat Removal (RHR) System is placed into service.

The SLB radiological analysis assumes that offsite power is lost at the same time as the pipe break occurs outside containment. Reactor trip occurs after the generation of an SI signal on low steamline pressure. The affected SG blows down completely and steam is vented directly to the atmosphere. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends and the RHR System is placed in service.

Operation with iodine specific activity levels greater than the LCO limit is permissible if the activity levels do not exceed 60 μCi/gm for more than 48 hours.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The iodine specific activity in the reactor coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the noble gas specific activity in the reactor coolant is limited to 500 μCi/gm DOSE EQUIVALENT XE-133. The limits on specific activity ensure that offsite and control room doses will meet the appropriate SRP acceptance criteria (Ref. 2).

The SLB and SGTR accident analyses (Refs. 3 and 4) show that the calculated doses are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SLB or SGTR, lead to doses that exceed the SRP acceptance criteria (Ref. 2).

APPLICABILITY

In MODES 1, 2, 3, and 4, operation within the LCO limits for DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 is necessary to limit the potential consequences of an SLB or SGTR to within the SRP acceptance criteria (Ref. 2).

In MODES 5 and 6, the steam generators are not being used for decay heat removal, the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, the monitoring of RCS specific activity is not required.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the specific activity is ≤ 60 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is acceptable since it is expected that, if there were an iodine spike, the normal coolant iodine concentration would be restored within this time period. Also, there is a low probability of an SLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4c. This allowance permits entry into the applicable MODE(s), relying on Required Actions A.1 and A.2 while the DOSE EQUIVALENT I-131 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

BASES

ACTIONS (continued)

B.1

With the DOSE EQUIVALENT XE-133 in excess of the allowed limit, DOSE EQUIVALENT XE-133 must be restored to within limits within 48 hours. The allowed Completion Time of 48 hours is acceptable since it is expected that, if there were a noble gas spike, the normal coolant noble gas concentration would be restored within this time period. Also, there is a low probability of an SLB or SGTR occurring during this time period.

A Note permits the use of the provisions of LCO 3.0.4c. This allowance permits entry into the applicable MODE(s), relying on Required Action B.1 while the DOSE EQUIVALENT XE-133 LCO limit is not met. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, and the ability to restore transient-specific activity excursions while the plant remains at, or proceeds to, power operation.

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met, or if the DOSE EQUIVALENT I-131 is > 60 μCi/gm, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the noble gas specific activity of the reactor coolant at least once every 7 days. This measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in the noble gas specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The 7 day Frequency considers the unlikelihood of a gross fuel failure during this time.

If a specific noble gas nuclide listed in the definition of DOSE EQUIVALENT XE-133 in Specification 1.1, "Definitions," is not detected, it should be assumed to be present at the minimum detectable activity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1 (continued)

The Note modifies this SR to allow entry into and operating in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

SR 3.4.16.2

This Surveillance is performed to ensure iodine specific activity remains within the LCO limit during normal operation and following fast power changes when iodine spiking is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering noble gas activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following iodine spiking information; samples at other times would provide inaccurate results.

The Note modifies this SR to allow entry into and operation in MODE 4, MODE 3, and MODE 2 prior to performing the SR. This allows the Surveillance to be performed in those MODES, prior to entering MODE 1.

REFERENCES

1. 10 CFR 100.11, 1973.
2. Standard Review Plan (SRP), Section 15.1.5 Appendix A (SLB) and Section 15.6.3 (SGTR).
3. USAR Section 15.1.5.
4. USAR, Section 15.6.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of an SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for an SGTR assumes the contaminated secondary fluid is released to the atmosphere via SG atmospheric relief valves and safety valves.

The analysis for design basis accidents and transients other than an SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. For Refueling Outage 14 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tube sheet does not require plugging. The portion of the tubes below 17 inches from the top of the hot leg tube sheet is excluded from tube inspections (Ref. 7) The tube-to-tubesheet weld is not considered part of the tube.

BASES

LCO
(continued)

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

BASES

LCO (continued)

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm per SG. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to an SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

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

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is

BASES

ACTIONS

A.1 and A.2 (continued)

based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1 (continued)

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.17.2

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.9 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."

2. 10 CFR 50 Appendix A, GDC 19.

3. 10 CFR 100.

4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.

5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.

6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

7. License Amendment No. 162, "Wolf Creek Generating Station – Issuance of Exigent Amendment RE: Steam Generator (SG) Tube Surveillance Program (TAC NO. MC6757)," April 28, 2005.

BASES

ACTIONS

A.1 (continued)

the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 6 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power or by key locking the control in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in References 6 and 7, that can disable the function of both ECCS trains and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not apply to manual vent/drain valves, and to valves that cannot be inadvertently misaligned such as check valves. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

The ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the piping from the ECCS pumps to the RCS full of water by venting RHR and SI pump casings and accessible ECCS discharge piping high point vents ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This SR is satisfied by verifying that RHR and SI pump casings and accessible ECCS discharge piping high point vents are full of water by venting and/or ultrasonic testing (UT). The design of the centrifugal charging pump is such that significant noncondensible gases do not collect in the pump. Therefore, it is unnecessary to require periodic pump casing venting to ensure the centrifugal charging pump will remain OPERABLE. Accessible high point vents are those that can be reached without hazard or high radiation dose to personnel. This will also prevent water hammer, pump cavitation, and pumping of noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component

BASES

ACTIONS

B.1 (continued)

can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level (≥ 94% level) in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 verifies the boron concentration by sampling, calculation, or administrative means. 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 Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Chapter 6 and Chapter 15.

BASES

ACTIONS

A.1

If the Spray Additive System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 72 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not apply to manual vent/drain valves, and to valves that cannot be inadvertently misaligned such as check valves. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown (which may include the use of local or remote indicators), that those valves outside containment and capable of potentially being mispositioned are in the correct position. The 31 day Frequency is based on engineering judgement, is consistent with administrative controls governing valve operation, and ensures correct valve positions.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The spray additive tank site glass (ENLG0022) is utilized for meeting the SR since the control room level indicators do not provide conservative indication (Ref. 2). The 184 day Frequency was developed based on the low probability of an undetected change in tank volume occurring during the SR interval (the tank is isolated during normal unit operations). (Ref. 3).

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The 184 day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position upon receipt of an actual or simulated actuation of a containment High-3 pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the 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 was concluded to be acceptable from a reliability standpoint.

SR 3.6.7.5

To ensure correct pH level is established in the borated water solution provided by the Containment Spray System, the flow rate in the Spray Additive System is verified once every 5 years. Flow of ≥ 52 gpm through the eductor test loops (supplied from the RWST) is throttled to 17 psig at

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.5 (continued)

the eductor inlet to simulate flow from the Chemical Additive Tank. This SR provides assurance that the correct amount of NaOH will be metered into the flow path upon Containment Spray System initiation. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow rate.

REFERENCES

1. USAR, Chapter 15.6.5.4.
2. Configuration Change Package 09334.
3. Performance Improvement Request 2006-0425.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators to the break.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Turbine Bypass System, and other auxiliary steam supplies from the steam generators.

The MSIV is a 28-inch gate valve with dual-redundant hydraulic actuation trains. Either actuation train can independently perform the safety function to fast-close the MSIV on demand. Each actuator train consists of a hydraulic accumulator controlled by solenoid valves on the associated MSIV. For each MSIV, one actuator train is associated with separation group 4 ("yellow"), and one actuator train is associated with separation group 1 ("red").

The MSIVs close on a main steam isolation signal generated by low steam line pressure, high steam line negative pressure rate or High-2 containment pressure. The MSIVs fail as is on loss of control or actuation power.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the USAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the USAR, Section 6.2.1.4 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the USAR, Section 15.1.5 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting case for the containment pressure analysis is the SLB inside containment, with initial reactor power at approximately 50% with loss of offsite power and the failure of one emergency diesel generator. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment. Due to reverse flow and failure of the MSIV to close,the additional mass and energy in the steam headers downstream from the other MSIV contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSVIs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting as far as MSIV OPERABILITY is concerned.

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

LCO

This LCO requires that four MSIVs and their associated actuator trains be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

An MSIV actuator train is considered OPERABLE when it is capable of fast-closing the associated MSIV on demand and within the required isolation time. This includes having adequate accumulator pressure to support fast-closure of the MSIV within the required isolation time and instrument air supply and pressure to the valve regulator is within limits.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 due to significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function. The MSIV actuator trains must be OPERABLE in MODES 1, 2, and 3 to support operation of the MSIV.

In MODE 4, the steam generator energy is low.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

BASES

ACTIONS

The LCO specifies OPERABILITY requirements for the MSIVs as well as for their associated actuator trains. The Conditions and Required Actions for TS 3.7.2 separately address inoperability of the MSIV actuator trains and inoperability of the MSIVs themselves.

A.1

With a single actuator train inoperable on one MSIV, action must be taken to restore the inoperable actuator train to OPERABLE status within 7 days. The 7-day Completion Time is reasonable in light of the dual-redundant actuator train design such that with one actuator train inoperable, the affected MSIV is still capable of closing on demand via the remaining OPERABLE actuator train. The 7-day Completion Time takes into account the redundant OPERABLE actuator train to the MSIV, reasonable time for repairs, and the low probability of an event occurring that requires the inoperable actuator train to the affected MSIV.

B.1

With an actuator train on one MSIV inoperable and an actuator train on an additional MSIV inoperable, such that the inoperable actuator trains are not in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 72 hours. With two actuator trains inoperable on two MSIVs, there is an increased likelihood that an additional failure (such as the failure of an actuation logic train) could cause one MSIV to fail to close. The 72-hour Completion Time is reasonable since the dual-redundant actuator train design ensures that with only one actuator train on each of two affected MSIVs inoperable, each MSIV is still capable of closing on demand.

C.1

With an actuator train on one MSIV inoperable and an actuator train on an additional MSIV inoperable, but with both inoperable actuator trains in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 24 hours. The 24-hour Completion Time provides a reasonable amount of time for restoring at least one actuator train since the dual-redundant actuator train design for each MSIV ensures that a single inoperable actuator train cannot prevent the affected MSIV(s) from closing on demand. With two actuator trains inoperable in the same separation group, an additional failure (such as the failure of an actuation logic train in the other separation group) could cause both affected MSIVs to fail to close on demand. The 24 hour

BASES

ACTIONS

C.1 (continued)

Completion Time takes into the redundant OPERABLE actuator trains to the affected MSIVs and the low probability of an event occurring that requires the inoperable actuator trains to the affected MSIVs.

D.1

Required Action D.1 provides assurance that the appropriate Action is entered for the affected MSIV if its associated actuator trains become inoperable. Failure of both actuator trains for a single MSIV results in the inability to close the affected MSIV on demand.

E.1

With three or more MSIV actuator trains inoperable or when Required Action A.1, B.1, or C.1 cannot be completed within the required Completion Time, the affected MSIVs may be incapable of closing on demand and must be immediately declared inoperable. Having three actuator trains inoperable could involve two inoperable actuator trains on one MSIV and one inoperable actuator train on another MSIV, or an inoperable actuator train on each of three MSIVs, for which the inoperable actuator trains could all be in the same separation group or be staggered among the two separation groups.

Depending on which of these conditions or combinations is in effect, the condition or combination could mean that all of the affected MSIVs remain capable of closing on demand (due to the dual-redundant actuator train design), or that at least one MSIV is inoperable, or that with an additional single failure up to three MSIVs could be incapable of closing on demand. Therefore, in some cases, immediately declaring the affected MSIVs inoperable is conservative (when some or all of the affected MSIVs may still be capable of closing on demand even with a single additional failure), while in other cases it is appropriate (when at least one of the MSIVs would be inoperable, or up to three could be rendered inoperable by an additional single failure). Required Action E.1 is conservatively based on the worst-case condition and therefore requires immediately declaring all the affected MSIVs inoperable. Declaring two or more MSIVs inoperable while in MODE 1 requires entry into LCO 3.0.3.

BASES

ACTIONS (continued)

F.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs. Condition F is entered when one MSIV is inoperable in MODE 1, including when both actuator trains for one MSIV are inoperable. When only one actuator train is inoperable on one MSIV, Condition A applies.

The 8 hour Completion Time is consistent with that allowed for containment isolation valves that isolate a closed system penetrating containment. This time is reasonable due to the relative stability of the closed system which provides an additional passive means for containment isolation.

G.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition H would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

H.1 and H.2

Condition H is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is consistent with that allowed in Condition F.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid.

BASES

ACTIONS

H.1 and H.2 (continued)

The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

I.1 and I.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV isolation time is ≤ 5.0 seconds on an actual or simulated actuation signal from each actuator train. The MSIV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage.

The Frequency is in accordance with the Inservice Testing Program.

This test can be conducted in MODE 3 with the unit at operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

This SR verifies that each actuator train can close its respective MSIV on an actual or simulated actuation signal. The manual fast close hand switch in the control room provides an acceptable actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.2 (continued)

The frequency of MSIV testing is every 18 months. The 18 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 10.3.
2. USAR, Section 6.2.
3. USAR, Section 15.1.5.
4. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs)

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The Main Feedwater Regulation Valves (MFRVs) function to control feedwater flow to the SGs.

The MFIV is a 14-inch gate valve with a dual-redundant hydraulic actuator. Either actuation train can independently perform the safety function to fast-close the MFIV on demand. Each actuator train consists of a hydraulic accumulator controlled by solenoid valves on the associated MFIV. For each MFIV, on actuator train is associated with separation group 4 ("yellow"), and one actuator trains is associated with separation group 1 ("red").

The MFRVs are air-operated angle valves used to control feedwater flow to the SGs from between 20% and full power. The MFRV bypass valves are air-operated globe valves used to control flow to the SGs up to 25% power.

Closure of the MFIVs terminates main feedwater flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs effectively terminates the addition of main feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The MFIVs isolate the nonsafety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV is located on each MFW line, outside but close to containment. The MFIVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV closure. The piping volume from these valves to the steam generators is accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

BASES

BACKGROUND (continued)

The MFIVs close on receipt of any safety injection signal, a T_{avg} - Low coincident with reactor trip (P-4), a low-low steam generator level, or steam generator water level - high high signal. They may also be actuated manually. In addition to the MFIVs, a check valve insidecontainment is available. The check valve isolates the feedwater line, penetrating containment, and ensures the pressure boundary of any intact loop not receiving auxiliary feedwater.

The MFIV actuators consist of two separate pneumatic-hydraulic power trains each receiving an actuation signal from one of the redundant ESFAS channels. A single active failure in one power train would not prevent the other power train from functioning. The MFIVs provide the primary success path for events requiring feedwater isolation and isolation of nonsafety related portions from the safety related portion of the system, such as, for auxiliary feedwater addition.

A description of the MFIVs and MFRVs is found in the USAR, Section 10.4.7 (Ref. 1).

APPLICABLE SAFETY ANALYSES

Credit is taken in accident analysis for the MFIVs to close on demand. The safety function of the MFRVs and associated bypass valves credited in accident analysis is to provide a backup to the MFIVs for the potential failure of an MFIV to close even though the MFRVs are located in the nonsafety related portion of the feedwater system. Further assurance of feedwater flow termination is provided by the SGFP trip function; however, this is not credited in accident analysis. The accident analysis credits the main feedwater check valves as backup to the MFIVs to prevent SG blowdown for pipe ruptures in the non-seismic Category I portions of the feedwater system outside containment.

Criterion 3 of 10 CFR 50.36(c)(2)(ii) indicates that components that are part of the primary success path and that actuate to mitigate an event that presents a challenge to a fission product barrier should be in Technical Specifications. The primary success path of a safety sequence analysis consists of the combination and sequences of equipment needed to operate (including consideration of the single failure criteria) so that the plant response to the event remains within appropriate acceptance criteria. The primary success path does not include backup and diverse equipment. The MFIVs, with their dual-redundant actuators, are the primary success path for feedwater isolation; the MFRVs, bypass valves, and the SGFP trip are backup and diverse equipment. Therefore, only the MFIVs are incorporated into Technical Specifications. The MFIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

This LCO ensures that the MFIVs will isolate MFW flow to the steam generators, following an FWLB or main steam line break. These valves will also isolate the nonsafety related portions from the safety related portions of the system.

This LCO requires that four MFIVs and their associated actuator trains be OPERABLE. The MFIVs are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

An MFIV actuator train is considered OPERABLE when it is capable of fast-closing the associated MFIV on demand and within the required isolation time. This includes having adequate accumulator pressure to support fast-closure of the MFIV within the required isolation time and instrument air supply and pressure to the valve regulator is within limits.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A feedwater isolation signal on high steam generator level is relied on to terminate an excess feedwater flow event, and failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MFIVs must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. In MODES 1, 2, and 3, the MFIVs are required to be OPERABLE to perform their isolation function and limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed, they are already performing their safety function. The MFIV actuator trains must be OPERABLE in MODES 1, 2, and 3 to support operation of the MFIV.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs can be closed since MFW is not required.

ACTIONS

The LCO specifies OPERABILITY requirements for the MFIVs as well as for their associated actuator trains. The Conditions and Required Actions for TS 3.7.3 separately address inoperability of the MFIV actuator trains and inoperability of the MFIVs themselves.

BASES

ACTIONS (continued)

A.1

With a single actuator train inoperable on one MFIV, action must be taken to restore the inoperable actuator train to OPERABLE status within 7 days. The 7-day Completion Time is reasonable in light of the dual-redundant actuator train design such that with one actuator train inoperable, the affected MFIV is still capable of closing on demand via the remaining OPERABLE actuator train. The 7-day Completion Time takes into account the redundant OPERABLE actuator train to the MFIV, reasonable time for repairs, and the low probability of an event occurring that requires the inoperable actuator train to the affected MFIV.

B.1

With an actuator train on one MFIV inoperable and an actuator train on an additional MFIV inoperable, such that the inoperable actuator trains are not in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 72 hours. With two actuator trains inoperable on two MFIVs, there is an increased likelihood that an additional failure (such as the failure of an actuation logic train) could cause one MFIV to fail to close. The 72-hour Completion Time is reasonable since the dual-redundant actuator train design ensures that with only one actuator train on each of two affected MFIVs inoperable, each MFIV is still capable of closing on demand.

C.1

With an actuator train on one MFIV inoperable and an actuator train on an additional MFIV inoperable, but with both inoperable actuator trains in the same separation group, action must be taken to restore one of the inoperable actuator trains to OPERABLE status within 24 hours. The 24-hour Completion Time provides a reasonable amount of time for restoring at least one actuator train since the dual-redundant actuator train design for each MFIV ensures that a single inoperable actuator train cannot prevent the affected MFIV(s) from closing on demand. With two actuator trains inoperable in the same separation group, an additional failure (such as the failure of an actuation logic train in the other separation group) could cause both affected MFIVs to fail to close on demand. The 24 hour Completion Time takes into the redundant OPERABLE actuator trains to the affected MFIVs and the low probability of an event occurring that requires the inoperable actuator trains to the affected MFIVs.

BASES

ACTIONS (continued)

D.1

Required Action D.1 provides assurance that the appropriate Action is entered for the affected MFIV if its associated actuator trains become inoperable. Failure of both actuator trains for a single MFIV results in the inability to close the affected MFIV on demand.

E.1

With three or more MFIV actuator trains inoperable or when Required Action A.1, B.1, or C.1 cannot be completed within the required Completion Time, the affected MFIVs may be incapable of closing on demand and must be immediately declared inoperable. Having three actuator trains inoperable could involve two inoperable actuator trains on one MFIV and one inoperable actuator train on another MFIV, or an inoperable actuator train on each of three MFIVs, for which the inoperable actuator trains could all be in the same separation group or be staggered among the two separation groups.

Depending on which of these conditions or combinations is in effect, the condition or combination could mean that all of the affected MFIVs remain capable of closing on demand (due to the dual-redundant actuator train design), or that at least one MFIV is inoperable, or that with an additional single failure up to three MFIVs could be incapable of closing on demand. Therefore, in some cases, immediately declaring the affected MFIVs inoperable is conservative (when some or all of the affected MFIVs may still be capable of closing on demand even with a single additional failure), while in other cases it is appropriate (when at least one of the MFIVs would be inoperable, or up to three could be rendered inoperable by an additional single failure). Required Action E.1 is conservatively based on the worst-case condition and therefore requires immediately declaring all the affected MFIVs inoperable.

F.1 and F.2

Condition F is modified by a Note indicating that separate Condition entry is allowed for each MFIV.

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 4 hours. When these valves are closed, they are performing their required safety function. Condition F is entered when one or more MFIV is inoperable in MODE 1, including when both actuator trains for one MFIV are inoperable. When only one actuator train is inoperable on one MFIV, Condition A applies.

BASES

ACTIONS

F.1 and F.2 (continued)

The 4 hour Completion Time takes into account the redundancy afforded by the dual-redundant actuators on the MFIVs and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 4 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed must be verified on a periodic basis that they are closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed.

G.1 and G.2

If the MFIV(s) cannot be restored to OPERABLE status, or closed, within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed 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 3.7.3.1

This SR verifies that the closure time of each MFIV is ≤ 5 seconds on an actual or simulated main feedwater isolation actuation signal from each actuator train. The MFIV closure time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. This is consistent with Regulatory Guide 1.22 (Ref. 4)

The Frequency for this SR is in accordance with the Inservice Testing Program. Operating experience has shown that these components usually pass the Surveillance when performed at the Inservice Testing Program Frequency. This test is conducted in MODE 3 with the unit at nominal operating temperature and pressure, as discussed in Reference 2. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.2

This SR verifies that each actuator train can close its respective MFIV on an actual or simulated actuation signal. The manual close hand switch in the control room provides an acceptable actuation signal. This Surveillance is normally performed upon returning the plant to operation following a refueling outage. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated

The frequency of MFIV testing is every 18 months. The 18 month Frequency for testing is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, this Frequency is acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 10.4.7.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. USAR, Table 7.3-14.
4. Regulatory Guide 1.22, Rev. 0.

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. Feedwater Line Break (FWLB);

b. Main Steam Line Break; and

c. Loss of MFW.

In addition, the minimum available AFW flow and system characteristics are considerations in the analysis of a small break loss of coolant accident (LOCA). The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of one motor driven AFW pump. This results in minimum assumed flow to the intact steam generators. One motor driven AFW pump would deliver to the broken MFW header at a flow rate throttled by the motor operated "smart" discharge valve until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generator by the residual flow from the affected pump plus the turbine driven AFW pump.

The BOP ESFAS automatically actuates the AFW turbine driven pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. DC power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each capable of automatically transferring the suction from

BASES

LCO (continued)

the CST to an ESW supply and supplying AFW to two steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of automatically transferring the suction from the CST to an ESW supply and supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE. The inoperability of a single supply line or a single suction isolation valve from an ESW train to the turbine driven AFW pump causes a loss of redundancy in ESW supply to the pump but does not render the turbine driven AFW train inoperable. The supply line begins at the point where the ESW piping branches into two lines, one supplying the motor driven AFW pump and one supplying the turbine driven AFW pump, and ends at the suction of the turbine driven AFW pump (Ref. 3). Therefore, with one ESW train inoperable, the associated motor driven AFW train is considered inoperable; and one turbine driven AFW pump supply line is considered inoperable. However, the turbine driven AFW train is OPERABLE based on the remaining OPERABLE ESW supply line.

In order for the turbine driven AFW pump and motor driven AFW pumps to be OPERABLE while the AFW System is in automatic control or above 10% RTP, the discharge flow control valves shall be in the full open position, except when the motor driven AFW pumps discharge flow control valves are automatically throttled in response to actual AFW flow (Ref. 5). When ≤ 10% RTP, the turbine driven AFW pump and motor driven AFW pumps remain OPERABLE with the discharge flow control valves throttled as needed to maintain steam generator levels.

The nitrogen accumulator tanks supplying the turbine driven AFW pump control valves and the steam generator atmospheric relief valves ensure an eight hour supply for the pump and valves.

Although the AFW System may be used in MODE 4 to remove decay heat, the LCO does not require the AFW System to be OPERABLE in MODE 4 since the RHR System is available for decay heat removal.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators but is not required since the RHR System is available and required to be OPERABLE in this MODE.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.4 (continued)

This SR is modified by a Note. The Note indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.5.5

This SR verifies that the AFW is properly aligned by verifying the flow paths from the CST to each steam generator prior to entering MODE 2 after more than 30 days in MODE 5 or 6. OPERABILITY of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

REFERENCES

1. USAR, Section 10.4.9.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. NRC letter (C. Poslusny to O. Maynard) dated December 16, 1998: "Wolf Creek Generating Station - Technical Specification Bases Change, Auxiliary Feedwater System."
4. Performance Improvement Request 2002-0945.
5. Condition Report 2006-000188.

B 3.7 PLANT SYSTEMS

B 3.7.13 Emergency Exhaust System (EES)

BASES

BACKGROUND

The Emergency Exhaust System serves both the auxiliary building and the fuel building. Following a loss of coolant accident (LOCA), safety related dampers isolate the auxiliary building, and the Emergency Exhaust System exhausts potentially contaminated air from the Emergency Core Cooling system (ECCS) areas and from the Hydrogen Purge System.

The Emergency Exhaust System filters airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. Following a LOCA, the system is aligned to the auxiliary building; however, a limited amount of air from the fuel building is processed through the Emergency Exhaust System to prevent excessive negative pressure in the auxiliary building.

The Emergency Exhaust System consists of two independent and redundant trains. Each train consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal absorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, dampers, and instrumentation also form part of the system, as well as heaters, functioning to reduce the relative humidity of the airstream. The system initiates filtered ventilation of the fuel building following receipt of a fuel building isolation signal.

The Emergency Exhaust System is on standby for an automatic start following receipt of a fuel building ventilation isolation signal (FBVIS) or a safety injection signal (SIS). Initiation of the LOCA (SIS) mode of operation takes precedence over any other mode of operation. In the LOCA mode the system is aligned to exhaust the auxiliary building.

Upon receipt of a fuel building ventilation isolation signal generated by gaseous radioactivity monitors in the fuel building exhaust line, normal air discharges from the building are terminated, the fuel building is isolated, and the stream of ventilation air discharges through the system filter trains.

BASES

BACKGROUND (continued)

The Emergency Exhaust System is discussed in the USAR, Sections 6.5.1, 9.4.2, 9.4.3, and 15.7.4 (Refs. 1, 2, and 3, respectively) because it may be used for normal, as well as post accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The Emergency Exhaust System design basis is established by the consequences of the limiting Design Basis Accidents (DBAs), which are a loss of coolant accident (LOCA) and a fuel handling accident (FHA). The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged, and one of the Emergency Exhaust System filter-adsorber unit is operating with a failed heater or humidistat. A reduced efficiency in the removal of organic iodine would occur if the heater failure occurred concurrently with high ambient relative humidity. The analysis of the LOCA assumes that radioactive materials leaked from the ECCS and Containment Spray System during the recirculation mode are filtered and adsorbed by the Emergency Exhaust System. The DBA analysis 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 handling 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. 5) and 1.25 (Ref. 4).

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 the guideline limits of 10 CFR 100 (Ref. 5) limits in the event of a LOCA or fuel handling accident.

The Emergency Exhaust System is considered OPERABLE when the individual components necessary to control releases from the auxiliary or fuel building are OPERABLE in both trains. An Emergency Exhaust System train is considered OPERABLE when its associated:

BASES

LCO (continued)

a. Fan is OPERABLE;

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

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

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 building or fuel building isolation is indicated.

APPLICABILITY

In MODE 1, 2, 3, or 4, the Emergency Exhaust System is required to be OPERABLE in the SIS mode of operation to provide fission product removal associated with potential radioactivity leaks during the post-LOCA recirculation phase of ECCS operation.

In MODE 5 or 6, when not moving irradiated fuel 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 handling area, 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.

BASES

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. 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.

B.1

If the auxiliary building boundary is inoperable such that a train of the Emergency Exhaust System operating in the SIS mode cannot establish or maintain the required negative pressure, action must be taken to restore an OPERABLE auxiliary building boundary within 24 hours. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period and the availability of the Emergency Exhaust System to provide a filtered release (albeit with potential for some unfiltered auxiliary building leakage).

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 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. 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.

BASES

APPLICABLE SAFETY ANALYSES (continued)	meeting the design basis of the unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of: a. An assumed loss of all offsite power or all onsite AC power; and b. A worst case single failure. The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System, separate and independent DGs for each train, and redundant LSELS 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. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. One offsite circuit consists of the #7 transformer feeding through the 13-48 breaker power the ESF transformer XNB01, which, in turn powers the NB01 bus through its normal feeder breaker. Transformer XNB01 may also be powered from the SL-7 supply through the 13-8 breaker provided the offsite 69 KV line is not connected to the 345 kV system. Another offsite circuit consists of the startup transformer feeding through breaker PA201 powering the ESF transformer XNB02, which, in turn powers the NB02 bus through its normal feeder breaker. 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. Upon failure of the DG lube oil keep warm system when the DG is in the standby condition, the DG is considered inoperable due to the inability to maintain engine lubrication (Ref. 15).

BASES

LCO (continued)

Upon failure of the DG jacket water keep warm system, the DG remains OPERABLE as long as jacket water temperature is ≥ 105 °F (Ref. 13).

Initiating an EDG start upon a detected undervoltage or degraded voltage condition, tripping of nonessential loads, and proper sequencing of loads, is a required function of LSELS and required for DG OPERABILITY. In addition, the LSELS Automatic Test Indicator (ATI) is an installed testing aid and is not required to be OPERABLE to support the sequencer function. Absence of a functioning ATI does not render LSELS inoperable.

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

For the offsite AC source, 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 and LSELS are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

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

ACTIONS

A Note prohibits the application of LCO 3.0.4b. to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4b., which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

BASES

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.

A.2

Required Action A.2, which only applies if the train cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps 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 remaining OPERABLE motor driven 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 either to evaluate and repair any discovered inoperabilities, or to supply the train without offsite power from the alternate offsite power circuit. Supplying both trains of the Class 1E AC electrical power distribution system from one offsite power source (either XNB01 or XNB02) is acceptable. 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

BASES

ACTIONS

A.2 (continued)

b. A required feature on the other train is inoperable and not in the safeguards position.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

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

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the 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

BASES

ACTIONS

A.3 (continued)

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 and an additional 72 hours 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. Although highly unlikely, this could continue indefinitely if not limited. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. This limits the time the plant can alternate between Conditions A, B, and E (see Completion Time Example 1.3-3). 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.

Tracking the 6 day Completion Time is a requirement for beginning the Completion Time “clock” that is in addition to the normal Completion Time requirements. With respect to the 6 day Completion Time, the “time zero” is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A “time zero,” and the “time zero” when LCO 3.8.1 was initially not met. Refer to Section 1.3, “Completion Times,” for a more detailed discussion of the purpose of the “from discovery of failure to meet the LCO portion of the Completion Time.

The Completion Time is modified by a Note. The Note modifies the Completion Time and allows 10 days from discovery of failure to meet the LCO during the use of the 7 day Completion Time in Required Action B.4.2.2.

The 10 day Completion Time specified in the Note 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 using the 7 day Completion Time of Required Action B.4.2.2 and that DG is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable and an additional 72 hours allowed prior to complete restoration of the LCO. Although highly unlikely, this could continue indefinitely if not limited. The 10 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. This limits the time the plant can alternate between Conditions A, B, and D (see Completion Time Example 1.3-3).

BASES

ACTIONS

A.3 (continued)

Tracking the 10 day Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the 10 day Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A "time zero," and the "time zero" when LCO 3.8.1 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO portion of the Completion Time."

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical redundant required features. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. 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 remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

BASES

ACTIONS

B.2 (continued)

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

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable and not in the safeguards position.

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 OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, it 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

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

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 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 is not affected by the same problem as the inoperable DG.

B.4.1, B.4.2.1, and B.4.2.2

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.

The Completion Time of 72 hours for Required Action B.4.1 applies when a DG is discovered or determined to be inoperable, such as due to a component or test failure, and requires time to effect repairs, or it may apply when a DG is rendered inoperable for the performance of maintenance during applicable MODES. The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA during this period.

The second Completion Time for Required Action B.4.1 also 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, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable and an additional 72 hours allowed prior to complete restoration of the LCO. Although highly unlikely, this could occur indefinetly if not limited. The 6 day Completion Time provides a limit on

BASES

ACTIONS

B.4.1, B.4.2.1, and B4.2.2 (continued)

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. This limits the time the plant can alternate between Conditions A, B, and E (see Completion Time Example 1.3-3). 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.

Tracking the 6 day Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the 6 day Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition B was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition B "time zero," and the "time zero" when LCO 3.8.1 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO portion of the Completion Time."

The Required Actions are modified by a Note that states that Required Actions B.4.2.1 and B.4.2.2 are only applicable for voluntary planned maintenance and may be used once per cycle per DG. Required Actions B.4.2.1 and B.4.2.2 only applies when a DG is declared or rendered inoperable for the performance of voluntary, planned maintenance activities. Required Action B.4.2.1 provides assurance that the required Sharpe Station gensets are available when a DG is out of service for greater than 72 hours. The availability of the required gensets are verified once per12 hours by locally monitoring various genset parameters.

The 7-day Completion Time of Required Action B.4.2.2 is a risk-informed allowed outage time (AOT) based on a plant-specific risk analysis. The Completion Time was established on the assumption that it would be used only for voluntary planned maintenance, inspections and testing. Use of Required Actions B.4.2.1 and B.4.2.2 are limited to once within an operating cycle (18 months) for each DG. Administrative controls applied during use of Required Action B.4.2.2 for voluntary planned maintenance activities ensure or require that (Ref. 15):

a. Weather conditions are conducive to an extended DG Completion Time. The extended DG Completion Time applies during the period of September 6 through April 22.

BASES

ACTIONS

B.4.1, B.4.2.1, and B4.2.2 (continued)

b. The offsite power supply and switchyard condition are conducive to an extended DG Completion Time, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed that would challenge offsite power availability.

c. Prior to relying on the required Sharpe Station gensets, the gensets are started and proper operation verified (i.e., the gensets reach rated speed and voltage). The Sharpe Station is not required to be operating the duration of the allowed outage time of the DG, however, it shall be capable of providing greater than 8 MW power to a dead bus (station blackout conditions) to power 1 ESF train. Within 8 months prior to utilization of Required Action B.4.2.2, a load capability test/verification will be performed on the Sharpe Station gensets. The load capability testing/verification will consist of either crediting a running of the gensets for greater than 1 hour to a load equal to or greater than required to supply safety related loads in the event of a station blackout.

d. No equipment or systems assumed to be available for supporting the extended DG Completion Time are removed from service. The equipment or systems assumed to be available (including required support systems, i.e., associated room coolers, etc.) are as follows:

- Auxiliary Feedwater System (three trains)
- Component Cooling Water System (both trains and all four pumps)
- Essential Service Water System (both trains)
- Emergency Core Cooling System (two trains).

If, while Required Action B.4.2.2 is being used, one (or more) of the above systems or components is determined or discovered to be inoperable, or if an emergent condition affecting DG OPERABILITY is identified, re-entry into Required Action B.2 and B.3 would be required, as applicable. In addition, the effect on plant risk would be assessed and any additional or compensatory actions taken, in accordance with the plant's program for implementation of 10 CFR 50.65(a)(4). The 7-day Completion Time would remain in effect for the DG if Required Action B.2 and B.3 are satisfied.

BASES

ACTIONS

B.4.1, B.4.2.1, and B4.2.2 (continued)

The second Completion Time specified in Required Action B.4.2.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of 10 days since initial failure to meet the LCO, to restore compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable and an additional 72 hours allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. Although highly unlikely, this could occur indefinitely if not limited. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. This limits the time the plant can alternate between Conditions A, B, and E (see Example 1.3-3).

Tracking the 10 day Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the 10 day Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition B was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition B "time zero," and the "time zero" when LCO 3.8.1 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO portion of the Completion Time."

C.1

If the availability of the required Sharpe Station gensets cannot be verified, the DG must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time begins upon entry into Condition C. However, the total time to restore an inoperable DG cannot exceed 7 days (per the Completion Time of Required Action B.4.2.2).

The Completion Time of 72 hours is consistent with Regulatory Guide 1.93 (Ref. 6). The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

D.1 and D.2

Required Action D.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps 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. 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. 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 remaining OPERABLE motor driven 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 D.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 and not in the safeguards position.

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

BASES

ACTIONS

D.1 and D.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D 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.

BASES

ACTIONS (continued)

E.1 and E.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 E are modified by a Note to indicate that when Condition E is entered with no AC source to any given train (i.e., to Train A or Train B), 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 E for a period that should not exceed 12 hours.

In Condition E, 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.

F.1

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

BASES

ACTIONS

F.1 (continued)

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

G.1 and G.2

Required Action G.1 provides assurance that the appropriate Action is entered for the affected DG and offsite circuit if its associated LSELS becomes inoperable. An LSELS failure results in the inability of the EDG to start upon a loss of ESF bus voltage or degraded voltage condition. Additionally, LSELS trips the ESF bus normal and alternate feeder supplies and trips non-essential loads. A sequencer failure results in the inability to start all or part of the safety loads powered from the associated ESF bus and thus when an LSELS is inoperable it is appropriate to immediately enter the Conditions for an inoperable DG and offsite circuit. Because an inoperable LSELS affects all or part of the safety loads, an immediate Completion Time is appropriate.

The LSELS is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the division. The 12 hour Completion Time of Required Action G.2 provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

H.1 and H.2

If the inoperable AC electric power sources or the load shedder and emergency load sequencer cannot be restored to OPERABLE status within the required Completion Time, or Required Actions B.1, B.2, B.3.1, B.3.2, B.4.1 or B.4.2 2 cannot be met within the required Completion Times, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

I.1

Condition I corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10), as addressed in the USAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. This minimum steady state output voltage of 3740 V is 90% of the nominal 4160 V output voltage. This value, which is specified in ANSI C84.1 (Ref. 11), allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level . This value provides for the OPERABILITY of required loads as shown by load flow calculations in support of NRC Branch Technical Position PSB-1. These calculations have demonstrated that no end use loads will be adversely affected from sustained operation above the degraded voltage allowable value as specified in SR 3.3.5.3. The 3740 V is above the calculated allowable value. The specified maximum steady state output voltage of 4320 V ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.1 (continued)

independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil temperature are being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions using one of the following signals and achieves required voltage and frequency within 12 seconds, and subsequently achieves steady state required voltage and frequency ranges:

a. Manual, or
b. Simulated loss of offsite power by itself, or
c. Safety Injection test signal.

The 12 second start requirement supports the assumptions of the design basis LOCA analysis in the USAR, Chapter 15 (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The 12 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, the 12 second start requirement of SR 3.8.1.7 applies.

A minimum voltage and frequency is specified rather than an upper and lower limit because DG acceleration is likely to overshoot the upper limit initially and then go through several oscillations prior to a voltage and frequency within the stated upper and lower bounds. The time to reach steady state could exceed 12 seconds, and result in a failure of the SR. However, on an actual emergency start, the DG would reach minimum voltage and frequency in ≤ 12 seconds at which time it would be loaded. Application of the load will dampen the oscillations. Therefore, only specifying the minimum voltage and frequency (at which the EDG can accept load) demonstrates the necessary capability of the DG to satisfy the requirements without including a potential for failing the Surveillance.

While reaching minimum voltage and frequency (at which the DG can accept load) in ≤ 12 seconds is an immediate test of OPERABILITY, the ability of the governor and voltage regulator to achieve steady state operation, and the time to do so are important indicators of continued OPERABILITY. Therefore, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance. This additional monitoring and trending is part of the TR 5.5.2, "Emergency Diesel Generator Reliability Program" and is not considered part of the SR. (Reference 14)

Since SR 3.8.1.7 requires a 12 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads and aligned to

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

provide standby power to the associated emergency buses. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source. The DG shall be operated continuously for the 60 minute time period per the guidance of Regulatory Guide 1.9, Position 2.2.2 (Ref. 3).

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Momentary power factor transients outside the normal range are acceptable during this surveillance since no power factor requirements are established by this SR. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that, with the DG in a standby condition, the fuel oil transfer pump starts on low level in the day tank standpipe and shuts down on high level in the day tank standpipe to automatically maintain the day tank fuel oil level above the DG fuel headers. The fuel oil standpipe must have adequate level to keep the fuel oil supply header to the engine injector pumps full, so that the engine can meet the required 12 second start time. The minimum fuel oil free surface elevation is required to be at least 86 inches from the bottom (outside diameter) of the tank. The transfer pump start/stop setpoints are controlled to maintain level in the standpipe in order to ensure there is sufficient fuel to meet the 12 second start requirement for the DG. This level also ensures adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is 31 days.

Periodically, the capability of the fuel oil transfer pump to supply the opposite train DG via the installed cross-connect line is verified.

SR 3.8.1.7

See SR 3.8.1.2.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Not Used.

SR 3.8.1.9

Not Used.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This testsimulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide for DG damage protection. While the DG is not expected to experience this transient during an event and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≥ 0.8 and ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and is intended to be consistent with expected fuel cycle lengths.

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(1), this Surveillance demonstrates the as-designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The DG autostart time of 12 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or residual heat removal (RHR)systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG systems to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

The Note 2 restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

The Note 2 restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9, Rev. 3, (Ref. 3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG (Refer to discussion of Note 3 below). The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of ≥ 0.8 and ≤ 0.9 at a voltage of 4160 +160 -420 volts and a frequency of 60 ± 1.2 Hz. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

Administrative controls for performing this SR in MODES 1 or 2, with the DG connected to an offsite circuit, ensure or require that:

a. Weather conditions are conducive for performing this SR.

b. The offsite power supply and switchyard conditions are conducive for performing this SR, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed.

c. No equipment or systems assumed to be available for supporting the performance of the SR are removed from service.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients outside the power factor range will not invalidate the test. Note 2 permits the elimination of the 2-hour overload test, provided that the combined emergency loads on a DG do not exceed its continuous duty rating.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 12 seconds. The 12 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3).

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.9, Rev. 3 (Ref. 3), this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive a close signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

The restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1, 2, 3 or 4. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.17

Demonstration of the test mode (parallel mode) override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready to load operation if a Safety Injection actuation signal is received during operation in the test mode. Ready to load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable.

This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. The restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.18

Under accident and loss of offsite power conditions loads are sequentially connected to the bus by the LSELS. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9, Rev. 3 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

The restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19 (continued)

The Note 2 restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post-work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9).

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil temperature maintained consistent with manufacturer recommendations.

SR 3.8.1.21

SR 3.8.1.21 is the performance of an ACTUATION LOGIC TEST using the LSELS automatic tester for each load shedder and emergency load sequencer train except that the continuity check does not have to be performed, as explained in the Note. This test is performed every 31 days on a STAGGERED TEST BASIS. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 0, January 1978.
11. ANSI C84.1-1982.
12. IEEE Standard 308-1978.
13. Configuration Change Package (CCP) 08052, Revision 1, April 23, 1999.
14. Amendment No. 161, April 21, 2005.
15. Performance Improvement Request 2005-3184.
16. Amendment No. 163, April 26, 2006.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. There are two sets of source range neutron flux monitors: (1) Westinghouse source range neutron flux monitors and (2) Gamma-Metrics source range neutron flux monitors.

The Westinghouse source range neutron flux monitors (SE-NI-0031 and SE-NI-0032) are BF_3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1 to 1E+6 cps). The detectors also provide continuous visual indication in the control room. The NIS is designed in accordance with the criteria presented in Reference 1.

The Gamma-Metrics source range neutron flux monitors (SE-NI-0060A and SE-NI-0061A) are fission chambers that provide indication of neutron flux from reactor shutdown to reactor full power level (1E-1 to 1E+5 cps). The monitors provide continuous visual indication in the control room to allow operators to monitor core flux.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as an improperly loaded fuel assembly.

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each monitor must provide visual indication in the control room.

When any of the safety related busses supplying power to one of the detectors (SE-NI-31 or 32) associated with the Westinghouse source range neutron flux monitors are taken out of service, the corresponding source range neutron flux monitor may be considered OPERABLE when its detector is powered from a temporary nonsafety related source of

BASES

LCO (continued)

power, provided the detector for the opposite source range neutron flux monitor is powered from its normal source. (Ref. 2) This allowance to power a detector from a temporary non-safety related source of power is also applicable to the Gamma-Metrics source range monitors. (Ref. 3)

The Westinghouse monitors are the normal source range monitors used during refueling activities. The Gamma-Metrics source range monitors provide an acceptable equivalent control room visual indication to the Westinghouse monitors in MODE 6, including CORE ALTERATIONS, with the complete fuel assembly inventory set within the reactor vessel or with the monitor(s) coupled to the core. (Ref. 3)

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and introduction into the RCS, coolant with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

BASES

ACTIONS (continued)

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and boron concentration changes inconsistent with Required Action A.2 are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The source range neutron detectors are maintained based on manufacturer's recommendations. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13, GDC 26, GDC 28, and GDC 29.
2. NRC letter (J. Stone to O. Maynard) dated October 3, 1997: "Wolf Creek Generating Station - Technical Specification Bases Change, Source Range Nuclear Instruments Power Supply Requirements."
3. Engineering Disposition for PIR 2004-1625, "Gamma-Metrics Detectors for Core Alterations," October 5, 2005.

BASES

BACKGROUND (continued)

least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations and the emergency personnel escape lock during fuel movements (Ref. 1).

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). Fuel handling accident, analyzed in Reference 2, assumes dropping a single irradiated fuel assembly. The time to close containment penetrations under administrative controls is assumed to be not more than a 2 hour period, consistent with the 2 hour period of release assumed in the accident analysis (Ref. 6). The requirements of LCO 3.9.7, "Refueling Pool Water Level," and the minimum decay time of 76 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, the personnel airlock, and the equipment hatch (which must be capable of being closed). For the OPERABLE containment purge penetrations, this LCO ensures that each penetration is 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.

One door in the emergency air lock must be closed and one door in the personnel air lock 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 and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of

BASES

LCO (continued)

irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the air lock following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of an open air lock can be quickly removed (Ref. 4). LCO 3.9.4.b is modified by a Note allowing an emergency escape air lock temporary closure device to be an acceptable replacement for an emergency air lock door.

The equipment hatch may be open during movement of irradiated fuel or CORE ALTERATIONS provided the hatch is capable of being closed and the water level in the refueling pool is maintained as required. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the containment during movement of irradiated fuel or CORE ALTERATIONS, 2) specified individuals are designated and readily available to close the equipment hatch following an evacuation that would occur in the event of a fuel handling accident, and 3) any obstructions (e.g., cables and hoses) that would prevent rapid closure of the equipment hatch can be quickly removed.

The LCO is modified by a Note allowing penetration flow paths with direct access from the containment atmosphere to the outside atmosphere to be unisolated under administrative controls. Administrative controls ensure that 1) appropriate personnel are aware of the open status of the penetration flow path during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, and 2) specified individuals are designated and readily available to isolate the flow path within 2 hours in the event of a fuel handling accident.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. 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,

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 76 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 all the dropped fuel assembly 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 percent of the rods of an additional assembly. 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 76 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 allowable limits (Refs. 4, 5, and 6).

Refueling pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	A minimum refueling pool water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 3.
APPLICABILITY	LCO 3.9.7 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.15, "Fuel Storage Pool Water Level."
ACTIONS	<u>A.1</u> With a water level of < 23 ft above the top of the reactor vessel flange, movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.7.1</u> Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2). The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

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B 2.1.1-4	14	DRR 03-0102	2/12/03
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B 3.0-9	19	DRR 04-1414	10/12/04
B 3.0-10	19	DRR 04-1414	10/12/04
B 3.0-11	19	DRR 04-1414	10/12/04
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B 3.3.2-47	20	DRR 04-1533	2/16/05
B 3.3.2-48	20	DRR 04-1533	2/16/05
B 3.3.2-49	20	DRR 04-1533	2/16/05
B 3.3.2-50	20	DRR 04-1533	2/16/05
B 3.3.2-51	20	DRR 04-1533	2/16/05
B 3.3.2-52	20	DRR 04-1533	2/16/05
B 3.3.2-53	25	DRR 06-0800	5/18/06
B 3.3.2-54	20	DRR 04-1533	2/16/05
B 3.3.2-55	20	DRR 04-1533	2/16/05
B 3.3.2-56	20	DRR 04-1533	2/16/05
B 3.3.2-57	20	DRR 04-1533	2/16/05
B 3.3.2-58	20	DRR 04-1533	2/16/05
B 3.3.3-1	0	Amend. No. 123	12/18/99
B 3.3.3-2	5	DRR 00-1427	10/12/00
B 3.3.3-3	0	Amend. No. 123	12/18/99
B 3.3.3-4	0	Amend. No. 123	12/18/99
B 3.3.3-5	0	Amend. No. 123	12/18/99
B 3.3.3-6	8	DRR 01-1235	9/19/01
B 3.3.3-7	21	DRR 05-0707	4/20/05
B 3.3.3-8	8	DRR 01-1235	9/19/01
B 3.3.3-9	8	DRR 01-1235	9/19/01
B 3.3.3-10	19	DRR 04-1414	10/12/04
B 3.3.3-11	19	DRR 04-1414	10/12/04
B 3.3.3-12	21	DRR 05-0707	4/20/05
B 3.3.3-13	21	DRR 05-0707	4/20/05
B 3.3.3-14	8	DRR 01-1235	9/19/01
B 3.3.3-15	8	DRR 01-1235	9/19/01
B 3.3.4-1	0	Amend. No. 123	12/18/99
B 3.3.4-2	9	DRR 02-1023	2/28/02
B 3.3.4-3	15	DRR 03-0860	7/10/03
B 3.3.4-4	19	DRR 04-1414	10/12/04
B 3.3.4-5	1	DRR 99-1624	12/18/99
B 3.3.4-6	9	DRR 02-0123	2/28/02
B 3.3.5-1	0	Amend. No. 123	12/18/99
B 3.3.5-2	1	DRR 99-1624	12/18/99
B 3.3.5-3	1	DRR 99-1624	12/18/99
B 3.3.5-4	1	DRR 99-1624	12/18/99

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TAB – B 3.3 INSTRUMENTATION (continued)			
B 3.3.5-5	0	Amend. No. 123	12/18/99
B 3.3.5-6	22	DRR 05-1375	6/28/05
B 3.3.5-7	22	DRR 05-1375	6/28/05
B 3.3.6-1	0	Amend. No. 123	12/18/99
B 3.3.6-2	0	Amend. No. 123	12/18/99
B 3.3.6-3	0	Amend. No. 123	12/18/99
B 3.3.6-4	0	Amend. No. 123	12/18/99
B 3.3.6-5	0	Amend. No. 123	12/18/99
B 3.3.6-6	0	Amend. No. 123	12/18/99
B 3.3.6-7	0	Amend. No. 123	12/18/99
B 3.3.7-1	0	Amend. No. 123	12/18/99
B 3.3.7-2	0	Amend. No. 123	12/18/99
B 3.3.7-3	0	Amend. No. 123	12/18/99
B 3.3.7-4	0	Amend. No. 123	12/18/99
B 3.3.7-5	0	Amend. No. 123	12/18/99
B 3.3.7-6	0	Amend. No. 123	12/18/99
B 3.3.7-7	0	Amend. No. 123	12/18/99
B 3.3.7-8	0	Amend. No. 123	12/18/99
B 3.3.8-1	0	Amend. No. 123	12/18/99
B 3.3.8-2	0	Amend. No. 123	12/18/99
B 3.3.8-3	0	Amend. No. 123	12/18/99
B 3.3.8-4	0	Amend. No. 123	12/18/99
B 3.3.8-5	0	Amend. No. 123	12/18/99
B 3.3.8-6	24	DRR 06-0051	2/28/06
B 3.3.8-7	0	Amend. No. 123	12/18/99
TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS)			
B 3.4.1-1	0	Amend. No. 123	12/18/99
B 3.4.1-2	10	DRR 02-0411	4/5/02
B 3.4.1-3	10	DRR 02-0411	4/5/02
B 3.4.1-4	0	Amend. No. 123	12/18/99
B 3.4.1-5	0	Amend. No. 123	12/18/99
B 3.4.1-6	0	Amend. No. 123	12/18/99
B 3.4.2-1	0	Amend. No. 123	12/18/99
B 3.4.2-2	0	Amend. No. 123	12/18/99
B 3.4.2-3	0	Amend. No. 123	12/18/99
B 3.4.3-1	0	Amend. No. 123	12/18/99
B 3.4.3-2	0	Amend. No. 123	12/18/99
B 3.4.3-3	0	Amend. No. 123	12/18/99
B 3.4.3-4	0	Amend. No. 123	12/18/99
B 3.4.3-5	0	Amend. No. 123	12/18/99
B 3.4.3-6	0	Amend. No. 123	12/18/99
B 3.4.3-7	0	Amend. No. 123	12/18/99
B 3.4.4-1	0	Amend. No. 123	12/18/99
B 3.4.4-2	29	DRR 06-1984	10/17/06
B 3.4.4-3	0	Amend. No. 123	12/18/99
B 3.4.5-1	0	Amend. No. 123	12/18/99
B 3.4.5-2	17	DRR 04-0453	5/26/04
B 3.4.5-3	29	DRR 06-1984	10/17/06
B 3.4.5-4	0	Amend. No. 123	12/18/99

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TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.5-5	12	DRR 02-1062	9/26/02
B 3.4.6-1	17	DRR 04-0453	5/26/04
B 3.4.6-2	29	DRR 06-1984	10/17/06
B 3.4.6-3	12	DRR 02-1062	9/26/02
B 3.4.6-4	12	DRR 02-1062	9/26/02
B 3.4.6-5	12	DRR 02-1062	9/26/02
B 3.4.7-1	12	DRR 02-1062	9/26/02
B 3.4.7-2	17	DRR 04-0453	5/26/04
B 3.4.7-3	29	DRR 06-1984	10/17/06
B 3.4.7-4	12	DRR 02-1062	9/26/02
B 3.4.7-5	12	DRR 02-1062	9/26/02
B 3.4.8-1	17	DRR 04-0453	5/26/04
B 3.4.8-2	19	DRR 04-1414	10/12/04
B 3.4.8-3	12	DRR 02-1062	9/26/02
B 3.4.8-4	12	DRR 02-1062	9/26/02
B 3.4.9-1	0	Amend. No. 123	12/18/99
B 3.4.9-2	0	Amend. No. 123	12/18/99
B 3.4.9-3	0	Amend. No. 123	12/18/99
B 3.4.9-4	0	Amend. No. 123	12/18/99
B 3.4.10-1	5	DRR 00-1427	10/12/00
B 3.4.10-2	5	DRR 00-1427	10/12/00
B 3.4.10-3	0	Amend. No. 123	12/18/99
B 3.4.10-4	5	DRR 00-1427	10/12/00
B 3.4.11-1	0	Amend. No. 123	12/18/99
B 3.4.11-2	1	DRR 99-1624	12/18/99
B 3.4.11-3	19	DRR 04-1414	10/12/04
B 3.4.11-4	0	Amend. No. 123	12/18/99
B 3.4.11-5	1	DRR 99-1624	12/18/99
B 3.4.11-6	0	Amend. No. 123	12/18/99
B 3.4.11-7	0	Amend. No. 123	12/18/99
B 3.4.12-1	1	DRR 99-1624	12/18/99
B 3.4.12-2	1	DRR 99-1624	12/18/99
B 3.4.12-3	0	Amend. No. 123	12/18/99
B 3.4.12-4	1	DRR 99-1624	12/18/99
B 3.4.12-5	1	DRR 99-1624	12/18/99
B 3.4.12-6	1	DRR 99-1624	12/18/99
B 3.4.12-7	0	Amend. No. 123	12/18/99
B 3.4.12-8	1	DRR 99-1624	12/18/99
B 3.4.12-9	19	DRR 04-1414	10/12/04
B 3.4.12-10	0	Amend. No. 123	12/18/99
B 3.4.12-11	0	Amend. No. 123	12/18/99
B 3.4.12-12	0	Amend. No. 123	12/18/99
B 3.4.12-13	0	Amend. No. 123	12/18/99
B 3.4.12-14	0	Amend. No. 123	12/18/99
B 3.4.13-1	0	Amend. No. 123	12/18/99
B 3.4.13-2	29	DRR 06-1984	10/17/06
B 3.4.13-3	29	DRR 06-1984	10/17/06
B 3.4.13-4	29	DRR 06-1984	10/17/06
B 3.4.13-5	29	DRR 06-1984	10/17/06
B 3.4.13-6	29	DRR 06-1984	10/17/06
B 3.4.14-1	0	Amend. No. 123	12/18/99

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TAB – B 3.4 REACTOR COOLANT SYSTEM (RCS) (continued)			
B 3.4.14-2	0	Amend. No. 123	12/18/99
B 3.4.14-3	0	Amend. No. 123	12/18/99
B 3.4.14-4	0	Amend. No. 123	12/18/99
B 3.4.14-5	16	DRR 03-1497	11/4/03
B 3.4.14-6	16	DRR 03-1497	11/4/03
B 3.4.15-1	31	DRR 06-2494	12/13/06
B 3.4.15-2	31	DRR 06-2494	12/13/06
B 3.4.15-3	31	DRR 06-2494	12/13/06
B 3.4.15-4	31	DRR 06-2494	12/13/06
B 3.4.15-5	31	DRR 06-2494	12/13/06
B 3.4.15-6	31	DRR 06-2494	12/13/06
B 3.4.15-7	31	DRR 06-2494	12/13/06
B 3.4.15-8	31	DRR 06-2494	12/13/06
B 3.4.16-1	31	DRR 06-2494	12/13/06
B 3.4.16-2	31	DRR 06-2494	12/13/06
B 3.4.16-3	31	DRR 06-2494	12/13/06
B 3.4.16-4	31	DRR 06-2494	12/13/06
B 3.4.16-5	31	DRR 06-2494	12/13/06
B 3.4.17-1	29	DRR 06-1984	10/17/06
B 3.4.17-2	29	DRR 06-1984	10/17/06
B 3.4.17-3	29	DRR 06-1984	10/17/06
B 3.4.17-4	29	DRR 06-1984	10/17/06
B 3.4.17-5	29	DRR 06-1984	10/17/06
B 3.4.17-6	29	DRR 06-1984	10/17/06
B 3.4.17-7	29	DRR 06-1984	10/17/06
TAB – B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)			
B 3.5.1-1	0	Amend. No. 123	12/18/99
B 3.5.1-2	0	Amend. No. 123	12/18/99
B 3.5.1-3	0	Amend. No. 123	12/18/99
B 3.5.1-4	0	Amend. No. 123	12/18/99
B 3.5.1-5	1	DRR 99-1624	12/18/99
B 3.5.1-6	1	DRR 99-1624	12/18/99
B 3.5.1-7	16	DRR 03-1497	11/4/03
B 3.5.1-8	1	DRR 99-1624	12/18/99
B 3.5.2-1	0	Amend. No. 123	12/18/99
B 3.5.2-2	0	Amend. No. 123	12/18/99
B 3.5.2-3	0	Amend. No. 123	12/18/99
B 3.5.2-4	0	Amend. No. 123	12/18/99
B 3.5.2-5	0	Amend. No. 123	12/18/99
B 3.5.2-6	0	Amend. No. 123	12/18/99
B 3.5.2-7	0	Amend. No. 123	12/18/99
B 3.5.2-8	24	DRR 06-0051	2/28/06
B 3.5.2-9	12	DRR 02-1062	9/26/02
B 3.5.2-10	0	Amend. No. 123	12/18/99
B 3.5.3-1	16	DRR 03-1497	11/4/03
B 3.5.3-2	19	DRR 04-1414	10/12/04
B 3.5.3-3	19	DRR 04-1414	10/12/04
B 3.5.3-4	16	DRR 03-1497	11/4/03
B 3.5.4-1	0	Amend. No. 123	12/18/99
B 3.5.4-2	0	Amend. No. 123	12/18/99

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TAB – B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) (continued)			
B 3.5.4-3	0	Amend. No. 123	12/18/99
B 3.5.4-4	0	Amend. No. 123	12/18/99
B 3.5.4-5	0	Amend. No. 123	12/18/99
B 3.5.4-6	26	DRR 06-1350	7/24/06
B 3.5.5-1	21	DRR 05-0707	4/20/05
B 3.5.5-2	21	DRR 05-0707	4/20/05
B 3.5.5-3	2	Amend. No. 132	4/24/00
B 3.5.5-4	21	DRR 05-0707	4/20/05
TAB – B 3.6 CONTAINMENT SYSTEMS			
B 3.6.1-1	0	Amend. No. 123	12/18/99
B 3.6.1-2	0	Amend. No. 123	12/18/99
B 3.6.1-3	0	Amend. No. 123	12/18/99
B 3.6.1-4	17	DRR 04-0453	5/26/04
B 3.6.2-1	0	Amend. No. 123	12/18/99
B 3.6.2-2	0	Amend. No. 123	12/18/99
B 3.6.2-3	0	Amend. No. 123	12/18/99
B 3.6.2-4	0	Amend. No. 123	12/18/99
B 3.6.2-5	0	Amend. No. 123	12/18/99
B 3.6.2-6	0	Amend. No. 123	12/18/99
B 3.6.2-7	0	Amend. No. 123	12/18/99
B 3.6.3-1	0	Amend. No. 123	12/18/99
B 3.6.3-2	0	Amend. No. 123	12/18/99
B 3.6.3-3	0	Amend. No. 123	12/18/99
B 3.6.3-4	0	Amend. No. 123	12/18/99
B 3.6.3-5	8	DRR 01-1235	9/19/01
B 3.6.3-6	8	DRR 01-1235	9/19/01
B 3.6.3-7	8	DRR 01-1235	9/19/01
B 3.6.3-8	8	DRR 01-1235	9/19/01
B 3.6.3-9	8	DRR 01-1235	9/19/01
B 3.6.3-10	8	DRR 01-1235	9/19/01
B 3.6.3-11	9	DRR 02-0123	2/28/02
B 3.6.3-12	20	DRR 04-1533	2/16/05
B 3.6.3-13	9	DRR 02-0123	2/28/02
B 3.6.3-14	9	DRR 02-0123	2/28/02
B 3.6.4-1	2	DRR 00-0147	4/24/00
B 3.6.4-2	0	Amend. No. 123	12/18/99
B 3.6.4-3	0	Amend. No. 123	12/18/99
B 3.6.5-1	0	Amend. No. 123	12/18/99
B 3.6.5-2	0	Amend. No. 123	12/18/99
B 3.6.5-3	13	DRR 02-1458	12/03/02
B 3.6.5-4	0	Amend. No. 123	12/18/99
B 3.6.6-1	0	Amend. No. 123	12/18/99
B 3.6.6-2	0	Amend. No. 123	12/18/99
B 3.6.6-3	1	DRR 99-1624	12/18/99
B 3.6.6-4	0	Amend. No. 123	12/18/99
B 3.6.6-5	0	Amend. No. 123	12/18/99
B 3.6.6-6	18	DRR 04-1018	9/1/04
B 3.6.6-7	0	Amend. No. 123	12/18/99
B 3.6.6-8	14	DRR 03-0102	2/12/03
B 3.6.6-9	13	DRR 02-1458	12/03/02

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TAB – B 3.6 CONTAINMENT SYSTEMS (continued)			
B 3.6.7-1	0	Amend. No. 123	12/18/99
B 3.6.7-2	0	Amend. No. 123	12/18/99
B 3.6.7-3	0	Amend. No. 123	12/18/99
B 3.6.7-4	29	DRR 06-1984	10/17/06
B 3.6.7-5	29	DRR 06-1984	10/17/06
B 3.6.8-1	0	Amend. No. 123	12/18/99
B 3.6.8-2	0	Amend. No. 123	12/18/99
B 3.6.8-3	19	DRR 04-1414	10/12/04
B 3.6.8-4	0	Amend. No. 123	12/18/99
B 3.6.8-5	0	Amend. No. 123	12/18/99
TAB – B 3.7 PLANT SYSTEMS			
B 3.7.1-1	0	Amend. No. 123	12/18/99
B 3.7.1-2	0	Amend. No. 123	12/18/99
B 3.7.1-3	0	Amend. No. 123	12/18/99
B 3.7.1-4	0	Amend. No. 123	12/18/99
B 3.7.1-5	0	Amend. No. 123	12/18/99
B 3.7.1-6	0	Amend. No. 123	12/18/99
B 3.7.2-1	30	DRR 06-2329	11/8/06
B 3.7.2-2	30	DRR 06-2329	11/8/06
B 3.7.2-3	30	DRR 06-2329	11/8/06
B 3.7.2-4	30	DRR 06-2329	11/8/06
B 3.7.2-5	30	DRR 06-2329	11/8/06
B 3.7.2-6	30	DRR 06-2329	11/8/06
B 3.7.2-7	30	DRR 06-2329	11/8/06
B 3.7.2-8	30	DRR 06-2329	11/8/06
B 3.7.3-1	30	DRR 06-2329	11/8/06
B 3.7.3-2	30	DRR 06-2329	11/8/06
B 3.7.3-3	30	DRR 06-2329	11/8/06
B 3.7.3-4	30	DRR 06-2329	11/8/06
B 3.7.3-5	30	DRR 06-2329	11/8/06
B 3.7.3-6	30	DRR 06-2329	11/8/06
B 3.7.3-7	30	DRR 06-2329	11/8/06
B 3.7.4-1	1	DRR 99-1624	12/18/99
B 3.7.4-2	1	DRR 99-1624	12/18/99
B 3.7.4-3	19	DRR 04-1414	10/12/04
B 3.7.4-4	19	DRR 04-1414	10/12/04
B 3.7.4-5	1	DRR 99-1624	12/18/99
B 3.7.5-1	0	Amend. No. 123	12/18/99
B 3.7.5-2	0	Amend. No. 123	12/18/99
B 3.7.5-3	0	Amend. No. 123	12/18/99
B 3.7.5-4	26	DRR 06-1350	7/24/06
B 3.7.5-5	19	DRR 04-1414	10/12/04
B 3.7.5-6	19	DRR 04-1414	10/12/04
B 3.7.5-7	19	DRR 04-1414	10/12/04
B 3.7.5-8	14	DRR 03-0102	2/12/03
B 3.7.5-9	26	DRR 06-1350	7/24/06
B 3.7.6-1	0	Amend. No. 123	12/18/99
B 3.7.6-2	0	Amend. No. 123	12/18/99
B 3.7.6-3	0	Amend. No. 123	12/18/99
B 3.7.7-1	0	Amend. No. 123	12/18/99

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TAB – B 3.7 PLANT SYSTEMS (continued)			
B 3.7.7-2	0	Amend. No. 123	12/18/99
B 3.7.7-3	0	Amend. No. 123	12/18/99
B 3.7.7-4	1	DRR 99-1624	12/18/99
B 3.7.8-1	0	Amend. No. 123	12/18/99
B 3.7.8-2	0	Amend. No. 123	12/18/99
B 3.7.8-3	0	Amend. No. 123	12/18/99
B 3.7.8-4	0	Amend. No. 123	12/18/99
B 3.7.8-5	0	Amend. No. 123	12/18/99
B 3.7.9-1	3	Amend. No. 134	7/14/00
B 3.7.9-2	3	Amend. No. 134	7/14/00
B 3.7.9-3	3	Amend. No. 134	7/14/00
B 3.7.9-4	3	Amend. No. 134	7/14/00
B 3.7.10-1	0	Amend. No. 123	12/18/99
B 3.7.10-2	15	DRR 03-0860	7/10/03
B 3.7.10-3	0	Amend. No. 123	12/18/99
B 3.7.10-4	0	Amend. No. 123	12/18/99
B 3.7.10-5	0	Amend. No. 123	12/18/99
B 3.7.10-6	0	Amend. No. 123	12/18/99
B 3.7.10-7	0	Amend. No. 123	12/18/99
B 3.7.11-1	0	Amend. No. 123	12/18/99
B 3.7.11-2	0	Amend. No. 123	12/18/99
B 3.7.11-3	0	Amend. No. 123	12/18/99
B 3.7.11-4	0	Amend. No. 123	12/18/99
B 3.7.12-1	0	Amend. No. 123	12/18/99
B 3.7.13-1	24	DRR 06-0051	2/28/06
B 3.7.13-2	1	DRR 99-1624	12/18/99
B 3.7.13-3	24	DRR 06-0051	2/28/06
B 3.7.13-4	1	DRR 99-1624	12/18/99
B 3.7.13-5	1	DRR 99-1624	12/18/99
B 3.7.13-6	12	DRR 02-1062	9/26/02
B 3.7.13-7	1	DRR 99-1624	12/18/99
B 3.7.13-8	1	DRR 99-1624	12/18/99
B 3.7.14-1	0	Amend. No. 123	12/18/99
B 3.7.15-1	0	Amend. No. 123	12/18/99
B 3.7.15-2	0	Amend. No. 123	12/18/99
B 3.7.15-3	0	Amend. No. 123	12/18/99
B 3.7.16-1	5	DRR 00-1427	10/12/00
B 3.7.16-2	23	DRR 05-1995	9/28/05
B 3.7.16-3	5	DRR 00-1427	10/12/00
B 3.7.17-1	7	DRR 01-0474	5/1/01
B 3.7.17-2	7	DRR 01-0474	5/1/01
B 3.7.17-3	5	DRR 00-1427	10/12/00
B 3.7.18-1	0	Amend. No. 123	12/18/99
B 3.7.18-2	0	Amend. No. 123	12/18/99
B 3.7.18-3	0	Amend. No. 123	12/18/99
TAB – B 3.8 ELECTRICAL POWER SYSTEMS			
B 3.8.1-1	0	Amend. No. 123	12/18/99
B 3.8.1-2	0	Amend. No. 123	12/18/99
B 3.8.1-3	25	DRR 06-0800	5/18/06
B 3.8.1-4	25	DRR 06-0800	5/18/06

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.1-5	25	DRR 06-0800	5/18/06
B 3.8.1-6	25	DRR 06-0800	5/18/06
B 3.8.1-7	26	DRR 06-1350	7/24/06
B 3.8.1-8	26	DRR 06-1350	7/24/06
B 3.8.1-9	26	DRR 06-1350	7/24/06
B 3.8.1-10	26	DRR 06-1350	7/24/06
B 3.8.1-11	26	DRR 06-1350	7/24/06
B 3.8.1-12	26	DRR 06-1350	7/24/06
B 3.8.1-13	26	DRR 06-1350	7/24/06
B 3.8.1-14	26	DRR 06-1350	7/24/06
B 3.8.1-15	26	DRR 06-1350	7/24/06
B 3.8.1-16	26	DRR 06-1350	7/24/06
B 3.8.1-17	26	DRR 06-1350	7/24/06
B 3.8.1-18	26	DRR 06-1350	7/24/06
B 3.8.1-19	26	DRR 06-1350	7/24/06
B 3.8.1-20	26	DRR 06-1350	7/24/06
B 3.8.1-21	26	DRR 06-1350	7/24/06
B 3.8.1-22	26	DRR 06-1350	7/24/06
B 3.8.1-23	26	DRR 06-1350	7/24/06
B 3.8.1-24	26	DRR 06-1350	7/24/06
B 3.8.1-25	26	DRR 06-1350	7/24/06
B 3.8.1-26	26	DRR 06-1350	7/24/06
B 3.8.1-27	26	DRR 06-1350	7/24/06
B 3.8.1-28	26	DRR 06-1350	7/24/06
B 3.8.1-29	26	DRR 06-1350	7/24/06
B 3.8.1-30	26	DRR 06-1350	7/24/06
B 3.8.1-31	26	DRR 06-1350	7/24/06
B 3.8.1-32	26	DRR 06-1350	7/24/06
B 3.8.1-33	26	DRR 06-1350	7/24/06
B 3.8.2-1	0	Amend. No. 123	12/18/99
B 3.8.2-2	0	Amend. No. 123	12/18/99
B 3.8.2-3	0	Amend. No. 123	12/18/99
B 3.8.2-4	0	Amend. No. 123	12/18/99
B 3.8.2-5	12	DRR 02-1062	9/26/02
B 3.8.2-6	12	DRR 02-1062	9/26/02
B 3.8.2-7	12	DRR 02-1062	9/26/02
B 3.8.3-1	1	DRR 99-1624	12/18/99
B 3.8.3-2	0	Amend. No. 123	12/18/99
B 3.8.3-3	0	Amend. No. 123	12/18/99
B 3.8.3-4	1	DRR 99-1624	12/18/99
B 3.8.3-5	0	Amend. No. 123	12/18/99
B 3.8.3-6	0	Amend. No. 123	12/18/99
B 3.8.3-7	12	DRR 02-1062	9/26/02
B 3.8.3-8	1	DRR 99-1624	12/18/99
B 3.8.3-9	0	Amend. No. 123	12/18/99
B 3.8.4-1	0	Amend. No. 123	12/18/99
B 3.8.4-2	0	Amend. No. 123	12/18/99
B 3.8.4-3	0	Amend. No. 123	12/18/99
B 3.8.4-4	0	Amend. No. 123	12/18/99
B 3.8.4-5	0	Amend. No. 123	12/18/99
B 3.8.4-6	0	Amend. No. 123	12/18/99

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TAB – B 3.8 ELECTRICAL POWER SYSTEMS (continued)			
B 3.8.4-7	6	DRR 00-1541	3/13/01
B 3.8.4-8	0	Amend. No. 123	12/18/99
B 3.8.4-9	2	DRR 00-0147	4/24/00
B 3.8.5-1	0	Amend. No. 123	12/18/99
B 3.8.5-2	0	Amend. No. 123	12/18/99
B 3.8.5-3	0	Amend. No. 123	12/18/99
B 3.8.5-4	12	DRR 02-1062	9/26/02
B 3.8.5-5	12	DRR 02-1062	9/26/02
B 3.8.6-1	0	Amend. No. 123	12/18/99
B 3.8.6-2	0	Amend. No. 123	12/18/99
B 3.8.6-3	0	Amend. No. 123	12/18/99
B 3.8.6-4	0	Amend. No. 123	12/18/99
B 3.8.6-5	0	Amend. No. 123	12/18/99
B 3.8.6-6	0	Amend. No. 123	12/18/99
B 3.8.7-1	0	Amend. No. 123	12/18/99
B 3.8.7-2	5	DRR 00-1427	10/12/00
B 3.8.7-3	0	Amend. No. 123	12/18/99
B 3.8.7-4	0	Amend. No. 123	12/18/99
B 3.8.8-1	0	Amend. No. 123	12/18/99
B 3.8.8-2	0	Amend. No. 123	12/18/99
B 3.8.8-3	0	Amend. No. 123	12/18/99
B 3.8.8-4	12	DRR 02-1062	9/26/02
B 3.8.8-5	12	DRR 02-1062	9/26/02
B 3.8.9-1	0	Amend. No. 123	12/18/99
B 3.8.9-2	0	Amend. No. 123	12/18/99
B 3.8.9-3	0	Amend. No. 123	12/18/99
B 3.8.9-4	0	Amend. No. 123	12/18/99
B 3.8.9-5	0	Amend. No. 123	12/18/99
B 3.8.9-6	0	Amend. No. 123	12/18/99
B 3.8.9-7	0	Amend. No. 123	12/18/99
B 3.8.9-8	1	DRR 99-1624	12/18/99
B 3.8.9-9	0	Amend. No. 123	12/18/99
B 3.8.10-1	0	Amend. No. 123	12/18/99
B 3.8.10-2	0	Amend. No. 123	12/18/99
B 3.8.10-3	0	Amend. No. 123	12/18/99
B 3.8.10-4	0	Amend. No. 123	12/18/99
B 3.8.10-5	12	DRR 02-1062	9/26/02
B 3.8.10-6	12	DRR 02-1062	9/26/02
TAB – B 3.9 REFUELING OPERATIONS			
B 3.9.1-1	0	Amend. No. 123	12/18/99
B 3.9.1-2	19	DRR 04-1414	10/12/04
B 3.9.1-3	19	DRR 04-1414	10/12/04
B 3.9.1-4	19	DRR 04-1414	10/12/04
B 3.9.2-1	0	Amend. No. 123	12/18/99
B 3.9.2-2	0	Amend. No. 123	12/18/99
B 3.9.2-3	0	Amend. No. 123	12/18/99
B 3.9.3-1	24	DRR 06-0051	2/28/06
B 3.9.3-2	24	DRR 06-0051	2/28/06
B 3.9.3-3	24	DRR 06-0051	2/28/06
B 3.9.3-4	24	DRR 06-0051	2/28/06

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TAB – B 3.9 REFUELING OPERATIONS (continued)			
B 3.9.4-1	23	DRR 05-1995	9/28/05
B 3.9.4-2	13	DRR 02-1458	12/03/02
B 3.9.4-3	25	DRR 06-0800	5/18/06
B 3.9.4-4	23	DRR 05-1995	9/28/05
B 3.9.4-5	13	DRR 02-1458	12/03/02
B 3.9.4-6	23	DRR 05-1995	9/28/05
B 3.9.5-1	0	Amend. No. 123	12/18/99
B 3.9.5-2	12	DRR 02-1062	9/26/02
B 3.9.5-3	12	DRR 02-1062	9/26/02
B 3.9.5-4	12	DRR 02-1062	9/26/02
B 3.9.6-1	0	Amend. No. 123	12/18/99
B 3.9.6-2	19	DRR 04-1414	10/12/04
B 3.9.6-3	12	DRR 02-1062	9/26/02
B 3.9.6-4	12	DRR 02-1062	9/26/02
B 3.9.7-1	25	DRR 06-0800	5/18/06
B 3.9.7-2	0	Amend. No. 123	12/18/99
B 3.9.7-3	0	Amend. No. 123	12/18/99

Note 1 The page number is listed on the center of the bottom of each page.

Note 2 The revision number is listed in the lower right hand corner of each page. The Revision number will be page specific.

Note 3 The change document will be the document requesting the change. Amendment No. 123 issued the improved Technical Specifications and associated Bases which affected each page. The NRC has indicated that Bases changes will not be issued with License Amendments. Therefore, the change document should be a DRR number in accordance with AP 26A-002.

Note 4 The date effective or implemented is the date the Bases pages are issued by Document Control.