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August 2, 2001

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

Subject: **Docket Nos. 50-361 and 50-362**
Cycle 11 Technical Specification Bases Page Updates
San Onofre Nuclear Generating Station, Units 2 & 3

Gentlemen:

Enclosed is the Cycle 11 update to the San Onofre Unit 2 and 3 Technical Specification (TS) Bases. As required by TS 5.4.4, changes to the TS Bases implemented without prior NRC approval are provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

Included in this update are all TS Bases pages that have been revised between July 1, 1999, and February 3, 2001. The pages are marked with change bars in the right hand margin to show where changes have been made.

Pages that are supplied without any change bars reflect text rollover from one page to the next as the result of additions or deletions.

If you have any questions on this subject, please call me or Mr. J. L. Rainsberry at (949) 368-7420.

Sincerely,

Enclosure

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ENCLOSURE

PART 1: SAN ONOFRE UNIT 2 REVISED BASES PAGES

PART 2: SAN ONOFRE UNIT 3 REVISED BASES PAGES

Bases Change Package Numbers

B97-040
B98-008
B99-009
B99-012
B99-013
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SAN ONOFRE UNIT 2 REVISED BASES PAGES

BASES

APPLICABLE SAFETY ANALYSES (continued)

CEA coil power programmers.

The acceptance criteria for addressing CEA inoperability or misalignment are that:

a. There shall be no violations of:

   1. specified acceptable fuel design limits, or
   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core must remain subcritical after accident transients.

Three types of misalignment are distinguished. During movement of a group, one CEA may stop moving while the other CEAs in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one CEA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the remaining CEAs to meet the SDM requirement with the maximum worth CEA stuck fully withdrawn (Ref. 3). If a CEA is stuck in the fully withdrawn position, its worth is added to the SDM requirement, since the safety analysis does not take two stuck CEAs into account. The third type of misalignment occurs when one CEA drops partially or fully into the reactor core. This event causes an initial power reduction followed by a return towards the original power due to positive reactivity feedback from the negative moderator temperature coefficient. Increased peaking during the power increase may result in excessive local linear heat rates (LHRs).

The effect of any misoperated CEA on the core power distribution will be assessed by the CEA calculators, and an appropriately augmented power distribution penalty factor will be supplied as input to the core protection calculators (CPCs). As the reactor core responds to the reactivity changes caused by the misoperated CEA and the ensuing reactor coolant and Doppler feedback effects, the CPCs will initiate a low DNBR or high local power density trip signal if specified acceptable fuel design limits (SAFDLs) are approached.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

All three charging pumps receive start signals from SIAS and the associated boric acid flow path valves open to provide emergency boration via the charging pumps.

The capacity of the charging pumps and the required amount of borated water stored in the RWST and BAMUs is sufficient to maintain shutdown margin during a plant cooldown to MODE 5 with a shutdown margin of at least 3%Δk/k at any time during plant life. The maximum expected boration capability requirements occurs at the end of core life from full power equilibrium xenon conditions. During this condition the required boric acid solution is supplied by the BAMU tanks with the contents in accordance with the LCS plus approximately 13,000 gallons of 2350 ppm borated water from the OPERABLE RWST.

The design of the boration systems incorporates a high degree of functional reliability by providing redundant components, an alternate path for charging and either offsite or onsite power supplies. Gravity feed lines from each Boric Acid Makeup (BAMU) tank and the RWST assures that a source of borated water is available to the charging pump suction header. Should the charging line inside containment be inoperable, the line may be isolated outside containment and flow redirected through the high pressure safety injection headers to assure boron injection. If the RWST gravity feed path to the charging pump suction were unavailable, sufficient borated water is available from the BAMU tanks (one or both in combination) to provide makeup to allow for plant cooldown to the point where the plant is depressurized sufficiently to allow injection of borated water into the RCS from the RWST using the HPSI pumps. If the normal power supply system should fail, the charging pumps, boric acid makeup pumps, and all related automatic control valves are powered from an emergency bus. The malfunction or failure of one active component would not reduce the ability to borate the RCS since an alternate flow path is always available for emergency boration.

The Boration Systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two boration flow paths will ensure that a means of controlling RCS boron concentration is available for normal plant operation and safe shutdown requirements. Both flow paths are required to ensure that no single failure can disable both boration flow paths.

(continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, boron injection flow paths are required to maintain RCS boron concentration and Shutdown Margin (SDM) requirements for maintenance, refueling and emergencies. A change in boron concentration may be required to obtain optimum CEA positioning and compensate for normal reactivity changes associated with changes in reactor coolant temperature, core burnup, and xenon concentration. The boration capability is sufficient to provide a SDM of 3.0% $\Delta k/k$ assuming the highest worth CEA is stuck out after xenon decay and cooldown to 200°F.

In MODES 1, 2, 3, and 4, two boron injection flow paths (Train A and Train B powered per the onsite emergency power supply specified by TS 3.8.1) shall be OPERABLE. The Train A flow path is composed of the requirements of paragraph I and III. The Train B flow path is composed of the requirements of paragraph II and III.

I. One of these combinations provide a Train A flow path via the charging pumps:

A.1 One Boric Acid Makeup (BAMU) tank (with the tank contents in accordance with the LCS 3.1.104) via the associated BAMU pump,

OR

A.2 Both BAMU tanks (with the combined contents of each tank in accordance with the LCS 3.1.104) via the associated BAMU pumps.

AND

II. One of these combinations provide a Train B flow path via the charging pumps:

A.1 One Boric Acid Makeup (BAMU) tank (with the tank contents in accordance with the LCS 3.1.104) via the associated gravity feed valve,

OR

A.2 Both BAMU tanks (with the combined contents of each tank in accordance with the LCS 3.1.104) via the associated gravity feed valves.

OR

A.3 The flow path from the OPERABLE Refueling Water Storage Tank (RWST) specified in TS 3.5.4.

AND

(continued)

BASES (continued)

APPLICABILITY (continued)

III. One of these two flow path shall be OPERABLE via the OPERABLE Refueling Water Storage Tank (RWST) as specified in TS 3.5.4, when the plant depressurizes:

A.1 RWST to the charging pumps,

OR

A.2 RWST to the HPSI pumps as specified in TS 3.5.2.

ACTIONS

A.1, B.1, B.2, and C.1

With less than two boron injection flow paths to the reactor coolant System OPERABLE, the required boron injection flow paths shall be restored to OPERABLE status within 72 hours. A boron injection flow path is not OPERABLE if it is not capable of performing its boron injection function in response to a SIAS. The 72 hour Completion Time allows minor component or corrective action without undue risk to plant safety from injection failures.

If the inoperable Boron injection flow path cannot be restored to an OPERABLE status within the allowed Completion Time the plant shall be brought to at least MODE 3, with the Shutdown Margin within TS 3.1.1 limits, within the next 6 hours. In addition, if an inoperable BAMU tank contributed to the boron injection system inoperability, some combination of the BAMU tanks, as described in the LCO Bases, shall be restored to OPERABLE within the next 7 days. If the required BAMU tanks cannot be restored to an OPERABLE status within the 7 day Completion Time, the plant must be brought to at least MODE 5 within the next 30 hours.

Based on operating experience, the Completion Times and required unit conditions are reasonably achievable in an orderly manner and without unnecessarily challenging unit systems from full power operation.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1 and 3.1.9.2

SR 3.1.9.1 verifies that the boron concentration of the available boric acid solution in the BAMU tanks is sufficient for reactivity control. SR 3.1.9.2 verifies that a sufficient volume of borated water is available for RCS makeup. The minimum required volume and concentration of stored boric acid in the BAMU tank(s) is dependent upon the RWST boron concentration and is specified in a Licensee Controlled Specification. The 7 day Surveillance Frequency ensures that an adequate initial water supply is available for boron injection.

SR 3.1.9.3 and 3.1.9.4

These SRs demonstrate that each automatic boration system pump and valve is operable and actuates as required. In response to an actual or simulated SIAS the charging pumps start, the VCT is isolated, and the charging pumps take suction from the OPERABLE BAMU tank(s) and RWST. Verification of the correct alignment for manual, power operated, and automatic valves in the Boration System Flow paths provides assurance that proper boration flow paths are available. These SRs do not apply to valves that are locked, sealed, or otherwise secured in position, because these valves were previously verified to be in the correct position.

SR 3.1.9.5

This SR verifies charging pump operability in accordance with the Inservice Testing Program. Such inservice inspections detect component degradation and incipient failures.

REFERENCES

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

2. 10 CFR 50, Appendix A, GDC 27.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.10 Boration Systems - Shutdown

BASES

BACKGROUND

The Chemical and Volume Control System (CVCS) functions to provide a means for reactivity control and maintain reactor coolant inventory, activity, and chemistry in accordance with GDC 26, 27, and 33 (Ref. 1, 2, and 3). The CVCS includes the letdown and boron injection subsystems. The boron injection subsystem is required to establish and maintain a safe shutdown condition for the reactor. The letdown portion of the CVCS is used for normal plant operation, however, it is not required for safety.

One OPERABLE boron injection flow path is required while operating in Modes 5 and 6. The required flow path may include either: 1) The Refueling Water Storage Tank (RWST) (T005 and/or T006) via a charging pump or High Pressure Safety Injection Pump, or; 2) A Boric Acid Makeup (BAMU) Tank via the BAMU pump or gravity feed valve to a charging pump. AC electrical power is available from the OPERABLE power sources specified by TS 3.8.2.

APPLICABLE SAFETY ANALYSES

The charging pumps inject concentrated boric acid into the RCS to provide negative reactivity control in MODES 5 and 6. With the RCS below 200°F one injection system is acceptable without single failure considerations on the basis of the stable reactor condition and additional restrictions on CORE ALTERATIONS.

Boron dilution is conducted under strict procedural controls which specify limits on the rate and magnitude of any required change in boron concentration. Therefore, the probability of a sustained or erroneous dilution is very low. In Mode 5 with less than full RCS inventory (i.e., pressurizer level <5%) administrative controls allow only one charging pump to be in operation and require that power be removed from the remaining two charging pumps with their breakers racked out. Since shutdown cooling is in service in this Mode, the Safety Analyses does not credit entrained water inventory in the steam generators. Analyses show that an inadvertent boron dilution while in MODE 5, results in the least time available for detection and termination of the event. The high neutron flux alarm on the startup channel instrumentation will alert the operator of a boron dilution event. The operator will terminate the dilution before losing shutdown margin by either turning off the charging

(continued)

BASES (continued)

LCO (continued)

OR

II. RWST (4150 gallons with a minimum of 2350 ppm boron, and 15.5%[1] level, Temperature ≥ 40°F and ≤ 100°F) via:

A. Charging Pump,

OR

B. High Pressure Safety Injection Pump.

The required boration flow path will ensure that a means of controlling RCS boron concentration is available for normal plant operation and safe shutdown requirements. One flow path is sufficient because of the stable reactor condition and administrative controls limiting core alterations when less than one boration flow path is OPERABLE.

APPLICABILITY

In MODES 5 and 6, one boron injection flow path is required to maintain RCS boron concentration and Shutdown Margin (SDM) requirements for maintenance and refueling. Boration injection capability is required to mitigate an inadvertent boron dilution event. The capacity of the charging pumps and the required amount of borated water stored in either the RWST or BAMUs is sufficient to maintain shutdown margin during a plant cooldown to MODE 6 with a shutdown margin of at least 3% $\Delta k/k$ at any time during plant life.

The required boration capability ensures that a SDM of 3.0% $\Delta k/k$ after xenon decay and cooldown from 200°F to 140°F is available. For this SDM requirement, 4150 gallons of borated water shall be available from either the BAMU tanks (41% Control Room indicated level includes TLU) or the RWST (15.5%[1] Control Room indicated level includes TLU and Design Basis Document defined margin), with a concentration of at least 2350 ppm boron.

1 15.5% level with tanks T005 and T006 cross connected (Reference 4, CCN-1). 17.0% level with tanks T005 (Reference 6) and T006 (Reference 4, CCN-3) isolated.

(continued)

BASES (continued)

ACTION

A.1

With no boron injection flow path to the reactor coolant System OPERABLE, all operations involving CORE ALTERATIONS or positive reactivity changes shall be suspended immediately. Required Action A.1 is modified by a note which permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM.

A boron injection flow path is not OPERABLE if it is not capable of performing its boron injection function. In consideration of the stable reactor configuration and the initial boron concentration, a core alteration is the only possible source for a significant increase in reactivity.

SURVEILLANCE REQUIREMENTS

SR 3.1.10.1, SR 3.1.10.2, and SR 3.1.10.3

SRs 3.1.10.1, 3.1.10.2, and 3.1.10.3, ensure that the required borated water supply is available. SR 3.1.10.1 verifies that the temperature of the boric acid solution in the RWST is ≥ 40°F and ≤ 100°F. The RWST water temperature is not expected to approach 40°F or 100°F, considering local meteorology and the large heat capacity of the RWST. Furthermore, at 40°F boric acid precipitation will not occur below a concentration of 4720 ppm boron. The maximum boric acid concentration in the tanks is 2800 ppm boron. However, SR 3.1.10.1 is only applicable when the RWST is the source of borated water and the outside air temperature is not within the normally expected range of 40 to 100°F.

The solubility of boric acid at 50°F is about 3.5 wt%. There is no similar requirement to verify BAMU Tank temperature 50°F is within the normal operating range of the building.

SR 3.1.10.2 and 3.1.10.3 verify that a sufficient amount of boron is available for RCS injection from either the BAMU tanks or the RWST. This requires a minimum of 4150 gallons of boric acid solution at a concentration of 2350 PPM Boron in either the RWST (15.5%[1] level indication) or a BAMU tank. A maximum boric acid solution concentration of 6119 ppm is specified for the BAMU Tank. The water volume limits are

[1] 15.5% level with tanks T005 and T006 cross connected (Reference 4, CCN-1). 17.0% level with tanks T005 (Reference 6) and T006 (Reference 4, CCN-3) isolated.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.10.1, SR 3.1.10.2, and SR 3.1.10.3 (continued)

specified relative to the top of the highest suction connection to the tank and considers vortexing, internal structures and instrument errors. The 7 day Surveillance Frequency ensures that a sufficient initial water supply is available for boron injection.

SR 3.1.10.4

These SRs demonstrate that each automatic boration system pump and valve is operable and actuates as required. In response to an actual or simulated SIAS the charging pumps start, the VCT is isolated, and the charging pumps take suction from the OPERABLE BAMU tank(s) and RWST. Verification of the correct alignment for manual, power operated, and automatic valves in the Boration System Flow paths provides assurance that proper boration flow paths are available. These SRs do not apply to valves that are locked, sealed, or otherwise secured in position, because these valves were previously verified to be in the correct position.

1. A flow path from either boric acid makeup tank with a minimum boron concentration of 2350 ppm and a minimum borated water volume of 4150 gallons, via either one of the boric acid makeup pumps, the blending tee or the gravity feed connection and any charging pump to the RCS, or;

2. The flow path from the RWST with a minimum borated water level of 15.5%[1] (includes TLU and Design Basis Document margin), a minimum boron concentration of 2350 ppm, and a solution temperature ≥ 40°F and ≤ 100°F via either a charging pump or a high pressure safety injection pump to the RCS.

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1 15.5% level with tanks T005 and T006 cross connected (Reference 4, CCN-1). 17.0% level with tanks T005 (Reference 6) and T006 (Reference 4, CCN-3) isolated.

(continued)

REFERENCES

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

2. 10 CFR 50, Appendix A, GDC 27.

3. 10 CFR 50, Appendix A, GDC 33.

4. J-BHB-029, "RWST Minimum Level to Maintain Safety Analysis Assumptions, Including TLU."

5. J-BGB-002, "TLU for Boric Acid Makeup Level Loops 2(3)LI0206C and 2(3)LI0208C."

6. J-BHB-021, "RWST 2(3)T005 & T006 Level Loop Uncertainties and Minimum Level Required During Modes 5 & 6."

BASES (continued)

ACTIONS (continued)

Two Notes have been added to the ACTIONS. Note 1 has been added to clarify the application of the Completion Time rules. The Conditions of this Specification may be entered independently for each Function. The Completion Time for the inoperable channel of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function. Note 2 was added to ensure review by the Onsite Review Committee is performed to discuss the desirability of maintaining the channel in the bypassed condition.

A.1 and A.2

Condition A applies to the failure of a single channel of one or more input parameters in the following ESFAS Functions:

1. Safety Injection Actuation Signal
   Containment Pressure – High
   Pressurizer Pressure – Low

2. Containment Spray Actuation Signal
   Containment Pressure – High High
   Automatic SIAS

3. Containment Isolation Actuation Signal
   Containment Pressure – High

4. Main Steam Isolation Signal
   Steam Generator Pressure – Low

5. Emergency Feedwater Actuation Signal SG #1 (EFAS-1)
   Steam Generator Level – Low

6. Emergency Feedwater Actuation Signal SG #2 (EFAS-2)
   Steam Generator Level – Low

ESFAS coincidence logic is normally two-out-of-four.

If one ESFAS channel is inoperable, startup or power operation is allowed to continue, providing the inoperable channel is placed in bypass or trip within 1 hour (Required Action A.1).

The Completion Time of 1 hour allotted to restore, bypass, or trip the channel is sufficient to allow the operator to take all appropriate actions for the failed channel and still ensures that the risk involved in operating with the failed channel is acceptable.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2 (continued)

The failed channel must be restored to OPERABLE status prior to entering MODE 2 following the next MODE 5 entry. With a channel bypassed, the coincidence logic is now in a two-out-of-three configuration. In this configuration, common cause failure of dependent channels cannot prevent trip. The Completion Time of prior to entering MODE 2 following the next MODE 5 entry is based on adequate channel to channel independence, which allows a two-out-of-three channel operation, since no single failure will cause or prevent an ESFAS actuation.

In the event that Trip Channel Bypass condition is indeterminate for a channel function (i.e., the pushbutton is depressed but indication lights do not energize or the indication lights remain energized after the pushbutton is released), the channel is conservatively assumed to be in Bypass and the provisions of this section apply. The pushbutton must be depressed to ensure the interlock with other channels is in effect. The function is administratively controlled to prevent operation of trip channel bypass for the same function in other channels.

In the event the channel does not actually go into Bypass when the pushbutton is depressed, the channel is free to process any trip channel, which is conservative. By having the channel in Bypass, even if the Bypass contacts do not close, the electrical interlock and administrative controls are implemented meeting the requirement to have an inoperable channel in Trip or Bypass. This prevents any other channel from being put into Bypass, preserving the function's ability to trip with any other single channel failed.

B.1 and B.2

Condition B applies to the failure of a single channel of one or more input parameters in the following ESFAS functions:

1. Recirculation Actuation Signal
   Refueling Water Storage Tank Level – Low

2. Emergency Feedwater Actuation Signal SG #1 (EFAS-1)
   SG Pressure Difference – High
   SG Pressure – Low

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

3. Emergency Feedwater Actuation Signal SG #2 (EFAS-2)
SG Pressure Difference – High
SG Pressure – Low

If one channel of RWST Level-Low for the RAS function, or SG Pressure Difference-High or SG Pressure-Low for the EFAS function is inoperable, startup or power operation is allowed to continue, providing the inoperable channel is placed in bypass within 1 hour (Required Action B.1). For these functions, operation with one channel in trip is undesirable due to the consequences of a spurious trip. With one channel in trip, the function is in a one-out-of-three configuration, and a single failure can lead to a spurious trip.

The Completion Time of 1 hour allotted to bypass or restore the channel is sufficient to allow the operator to take all appropriate actions for the failed channel and still ensures that the risk involved in operating with the failed channel is acceptable.

The failed channel must be restored to OPERABLE status prior to entering MODE 2 following the next MODE 5 entry. With a channel bypassed, the coincidence logic is now in a two-out-of-three configuration. In this configuration, common cause failure of dependent channels cannot prevent trip. The Completion Time of prior to entering MODE 2 following the next MODE 5 entry is based on adequate channel to channel independence, which allows a two-out-of-three channel operation, since no single failure will cause or prevent an ESFAS actuation.

In the event that Trip Channel Bypass condition is indeterminate for a channel function (i.e., the pushbutton is depressed but indication lights do not energize or the indication lights remain energized after the pushbutton is released), the channel is conservatively assumed to be in Bypass and the provisions of this section apply. The pushbutton must be depressed to ensure the interlock with other channels is in effect. The function is administratively controlled to prevent operation of trip channel bypass for the same function in other channels.

In the event the channel does not actually go into Bypass when the pushbutton is depressed, the channel is free to process any trip channel, which is conservative. By having the channel in Bypass, even if the Bypass contacts do not

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

close, the electrical interlock and administrative controls are implemented meeting the requirement to have an inoperable channel in Bypass. This prevents any other channel from being put into Bypass, preserving the function's ability to trip with any other single channel failed.

C.1

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODES even though two channels are inoperable, with one channel bypassed and one tripped. In this configuration, the protection system is in a one-out-of-two logic, which is adequate to ensure that no random failure will prevent protection system operation.

Condition B applies to the failure of two channels of one or more input parameters in the following ESFAS automatic trip Functions:

1. Safety Injection Actuation Signal
   Containment Pressure – High
   Pressurizer Pressure – Low

2. Containment Spray Actuation Signal
   Containment Pressure – High High
   Automatic SIAS

3. Containment Isolation Actuation Signal
   Containment Pressure – High

4. Main Steam Isolation Signal
   Steam Generator Pressure – Low

5. Emergency Feedwater Actuation Signal SG #1 (EFAS-1)
   Steam Generator Level – Low

6. Emergency Feedwater Actuation Signal SG #2 (EFAS-2)
   Steam Generator Level – Low

With two inoperable channels, power operation may continue, provided one inoperable channel is placed in bypass and the other channel is placed in trip within 1 hour. With one channel of protective instrumentation bypassed, the ESFAS Function is in two-out-of-three logic in the bypassed input

(continued)

BASES (continued)

ACTIONS

C.1 (continued)

parameter, but with another channel failed, the ESFAS may be operating with a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the ESFAS Function in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, ESFAS actuation will occur.

One of the two inoperable channels will need to be restored to operable status prior to the next required CHANNEL FUNCTIONAL TEST because channel surveillance testing on an OPERABLE channel requires that the OPERABLE channel be placed in bypass. However, it is not possible to bypass more than one ESFAS channel, and placing a second channel in trip will result in an ESFAS actuation. Therefore, if one ESFAS channel, is in trip and a second channel is in bypass, a third inoperable channel would place the unit in LCO 3.0.3.

D.1 and D2

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODES even though two channels are inoperable, with one channel bypassed and one tripped. In this configuration, the protection system is in a one-out-of-two logic, which is adequate to ensure that no random failure will prevent protection system operation. Condition D applies to the failure of two channels of one or more input parameters in the following ESFAS automatic trip Functions:

1. Recirculation Actuation Signal
   Refueling Water Storage Tank Level - Low

2. Emergency Feedwater Actuation Signal SG #1 (EFAS-1)
   SG Pressure Difference - High
   SG Pressure - Low

3. Emergency Feedwater Actuation Signal SG #2 (EFAS-2)
   SG Pressure Difference - High
   SG Pressure - Low

With two inoperable channels, power operation may continue, provided one inoperable channel is placed in bypass and the other channel is placed in trip within 1 hour. With one channel of protective instrumentation bypassed, the ESFAS

(continued)

BASES (continued)

ACTIONS

D.1 and D.2 (continued)

Function is in two-out-of-three logic in the bypassed input parameter, but with another channel failed, the ESFAS may be operating with a two-out-of-two logic. This is outside the assumptions made in the analyses and should be corrected. To correct the problem, the second channel is placed in trip. This places the ESFAS Function in a one-out-of-two logic. If any of the other OPERABLE channels receives a trip signal, ESFAS actuation will occur.

Action D.2 provides a limit of 7 days for operation with 2 inoperable channels. In the one-out-of-two configuration, a single channel failure can cause a spurious trip. For RAS and EFAS functions, a spurious trip can lead to undesireable consequences during certain Design Basis Events.

The 7 day time limit provides operational flexibility to perform a required CHANNEL FUNCTIONAL TEST on one channel (which is bypassed) while a second channel is inoperable (and is tripped).

The 7 day time limit also maintains acceptable core damage frequency as discussed in NSG 98-007, Time Limit for RAS or EFAS Channel in Trip (Reference 11).

As required by Section 5.5.2.14, a Configuration Risk Management Program is implemented in the event of Condition D.

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

Condition C applies to one automatic bypass removal channel inoperable. The only automatic bypass removal on an ESFAS is on the Pressurizer Pressure – Low signal. This bypass removal is shared with the RPS Pressurizer Pressure – Low bypass removal.

If the bypass removal channel for any operating bypass cannot be restored to OPERABLE status, the associated ESFAS channel may be considered OPERABLE only if the bypass is not in effect. Otherwise, the affected ESFAS channel must be declared inoperable, as in Conditions A and B, and the bypass either removed or the bypass removal channel repaired. The Bases for the Required Actions and required Completion Times are consistent with Conditions A and B.

(continued)

BASES (continued)

ACTIONS (continued)

F.1 and F.2

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable. The Note was added to allow the changing of MODES even though two channels are inoperable, with one channel bypassed and one tripped. In this configuration, the protection system is in a one-out-of-two logic, which is adequate to ensure that no random failure will prevent protection system operation.

Condition F applies to two inoperable automatic bypass removal channels. If the bypass removal channels for two operating bypasses cannot be restored to OPERABLE status, the associated ESFAS channel may be considered OPERABLE only if the bypass is not in effect. Otherwise, the affected ESFAS channels must be declared inoperable, as in Conditions C and D, and either the bypass removed or the bypass removal channel repaired. The restoration of one affected bypassed automatic trip channel must be completed prior to the next CHANNEL FUNCTIONAL TEST or the plant must shut down per LCO 3.0.3, as explained in Conditions C and D. Completion Times are consistent with Conditions C and D.

G.1 and G.2

If the Required Actions and associated Completion Times of Condition A, C, E, or F cannot be met for the Safety Injection Actuation Signal, Containment Spray Actuation Signal, Containment Isolation Actuation Signal, Main Steam Isolation Signal, or Emergency Feedwater Actuation Signal, or if the Required Actions and associated Completion Times of Condition B, D, E, or F cannot be met for the SG Pressure Difference-High input or the SG Pressure-Low input to the Emergency Feedwater Actuation Signal, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1 and H.2

If the Required Actions and associated Completion Times of Condition B, D, E, or F cannot be met for the Recirculation Actuation Signal, the plant must be brought to

(continued)

BASES (continued)

ACTIONS

H.1 and H.2 (continued)

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 MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

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

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

The Frequency, about once every shift, is based on operating experience that demonstrates channel failure is rare. Thus, performance of the CHANNEL CHECK guarantees that undetected overt channel failure is limited to 12 hours. Since the probability of two random failures in redundant channels in any 12 hour period is low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of displays associated with the LCO required channels.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.2 and SR 3.3.5.3

A CHANNEL FUNCTIONAL TEST is performed every 30 days on a STAGGERED TEST BASIS for SR 3.3.5.2 to ensure the entire channel will perform its intended function when needed.

LCO 3.3.5 Action A permits plant operation with one or more Functions with one automatic ESFAS trip channel inoperable until MODE 2 entry following the next MODE 5 entry (provided the Functional Unit is placed in bypass or trip). During plant operation in that condition, CHANNEL FUNCTIONAL TESTs on the inoperable Functions in that channel are not required (SR 3.0.1), and *n* remains at 4, where *n* is the total number of channels in the definition of STAGGERED TEST BASIS. Therefore, tests on the affected Functions in the remaining 3 channels may continue to be performed such that each channel is tested every 4 Surveillance Frequency intervals. Discussions with the NRC Technical Specifications Branch on this clarification are documented in Action Request 980601488-1.

The CHANNEL FUNCTIONAL TEST is part of an overlapping test sequence similar to that employed in the RPS. This sequence, consisting of SR 3.3.5.2, SR 3.3.5.3, SR 3.3.6.1, and SR 3.3.6.2, tests the entire ESFAS from the bistable input through the actuation of the individual subgroup relays. These overlapping tests are described in Reference 1. SR 3.3.5.2 and SR 3.3.6.1 are normally performed together and in conjunction with ESFAS testing. SR 3.3.6.2 verifies that the subgroup relays are capable of actuating their respective ESF components when de-energized. SR 3.3.5.3 is performed every 120 days to verify ESFAS channel bypass removal function.

These tests verify that the ESFAS is capable of performing its intended function, from bistable input through the actuated components. SRs 3.3.6.1 and 3.3.6.2 are addressed in LCO 3.3.6. SR 3.3.5.2 includes bistable tests.

A test signal is superimposed on the input in one channel at a time to verify that the bistable trips within the specified tolerance around the setpoint. This is done with the affected PPS trip channel bypassed.

SR 3.3.5.4 and SR 3.3.5.5

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor and the bypass removal

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

functions, if applicable. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational between successive surveillances. Measurement error determination, setpoint error determination, and calibration adjustment must be performed consistent with the plant specific setpoint analysis. The channel shall be left calibrated consistent with the assumptions of the current plant specific setpoint analysis. The 24 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.

SR 3.3.5.6

This Surveillance ensures that the train actuation response times are within the maximum values assumed in the safety analyses.

Response time testing acceptance criteria are included in Reference 9.

ESF RESPONSE TIME tests are conducted on a STAGGERED TEST BASIS of once every 24 months. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.5.7

SR 3.3.5.7 is a CHANNEL FUNCTIONAL TEST similar to SR 3.3.5.2 and SR 3.3.5.3, except SR 3.3.5.7 is performed within 120 days prior to startup and is only applicable to bypass functions. Since the Pressurizer Pressure – Low bypass is identical for both the RPS and ESFAS, this is the same Surveillance performed for the RPS in SR 3.3.1.13.

The CHANNEL FUNCTIONAL TEST for proper operation of the bypass permissives is critical during plant heatups because the bypasses may be in place prior to entering MODE 3 but must be removed at the appropriate points during plant

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

startup to enable the ESFAS Function. Consequently, just prior to startup is the appropriate time to verify bypass function OPERABILITY. Once the bypasses are removed, the bypasses must not fail in such a way that the associated ESFAS Function is inappropriately bypassed. This feature is verified by SR 3.3.5.2. The allowance to conduct this test once within 120 days prior to each reactor startup is based on a plant specific report based on the reliability analysis presented in topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation" (Refs. 8 and 10).

REFERENCES

1. SONGS Units 2 and 3 UFSAR, Section 7.3.
2. 10 CFR 50, Appendix A.
3. IEEE Standard 279-1971.
4. SONGS Units 2 and 3 UFSAR, Chapter 15.
5. 10 CFR 50.49.
6. PPS Setpoint Calculation CE-NPSD-570.
7. SONGS Units 2 and 3 UFSAR, Section 7.2.
8. CEN-327, May 1986, including Supplement 1, March 1989.
9. Licensee Controlled Specification 3.3.100, "RPS/ESFAS Response Times."
10. RPS/ESFAS Extended Test Interval Evaluation for 120 Days Staggered Testing at SONGS Units 2 and 3, Calculation Number 09/010-AS93-C-002, November 1993.
11. Report NSG 98-007, "Time Limit for RAS or EFAS Channel in Trip," April 17, 1998.

BASES (continued)

LCO (continued)

A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

APPLICABILITY

The DG – LOVS actuation Function is required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. For the Degraded Voltage Function, this LCO is applicable when the diesel generator circuit breaker is open. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE, so that it can perform its function on a loss of power or degraded power to the vital bus.

ACTIONS

A LOVS channel is inoperable when it does not satisfy the OPERABILITY criteria for the channel's function. The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the plant specific setpoint analysis. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. Determination of setpoint drift is generally made during the performance of a CHANNEL FUNCTIONAL TEST when the instrument is set up for adjustment to bring it within specification. If the actual trip setpoint is not within the Allowable Value, the channel is inoperable and the appropriate Conditions must be entered.

In the event a channel's trip setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition entered. The required channels are specified on a per DG basis.

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

one-out-of-two logic, which is adequate to ensure that no random failure will prevent protection system operation.

If the channel cannot be placed in bypass or trip within 1 hour, the Conditions and Required Actions for the associated DG made inoperable by DG – LOVS instrumentation are required to be entered. Alternatively, one affected channel is required to be bypassed and the other is tripped, in accordance with Required Action B.2. This places the Function in one-out-of-two logic. The 1 hour Completion Time is sufficient to perform the Required Actions.

One of the two inoperable channels will need to be restored to OPERABLE status prior to the next required CHANNEL FUNCTIONAL TEST because channel surveillance testing on an OPERABLE channel requires that the OPERABLE channel be placed in bypass. However, it is not allowed to bypass more than one DG – LOVS channel, and placing a second channel in trip will result in a loss of voltage diesel start signal.

After one channel is restored to OPERABLE status, the provisions of Condition A still apply to the remaining inoperable channel.

C.1

Condition C applies when more than two undervoltage or Degraded Voltage channels on a single bus are inoperable.

Required Action C.1 requires all but two channels to be restored to OPERABLE status within 1 hour. With more than two channels inoperable, the logic is not capable of providing the DG – LOVS signal for valid Loss of Voltage or Degraded Voltage conditions. The 1 hour Completion Time is reasonable to evaluate and take action to correct the degraded condition in an orderly manner and takes into account the low probability of an event requiring LOVS occurring during this interval.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2

A CHANNEL FUNCTIONAL TEST is performed every 24 months to ensure that the entire channel will perform its intended function when needed.

The Frequency of 24 months is based on plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 24 month Frequency is a rare event. The setpoint shall be left consistent and the assumptions of the current plant specific setpoint analysis.

SR 3.3.7.3

SR 3.3.7.3 is the performance of a CHANNEL CALIBRATION every 24 months. The CHANNEL CALIBRATION verifies the accuracy of each component within the instrument channel. The CHANNEL CALIBRATION does not include the Potential Transformer (PT) that feeds the undervoltage relays for LOVS and DV. All PTs are designed and manufactured per ANSI/IEEE Standard C57.13 - Requirement for Instrument Transformers. This standard specifically clarifies that if the PT is used in relaying, only the PT ratio needs to be determined, and this may be achieved either experimentally or by computation. The PT that feeds the undervoltage relays for LOVS and DV are used only for relay application. For these PTs, the PT ratio has been determined by the manufacturer and need not be repeated in the field.

The CHANNEL CALIBRATION includes calibration of the undervoltage relays and demonstrates that the equipment falls within the specified operating characteristics defined by the manufacturer. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive surveillances to ensure the instrument channel remains operational. Measurement error determination, setpoint error determination, and calibration adjustment must be performed consistent with the plant specific setpoint analysis. The channel shall be left calibrated consistent with the assumptions of the current plant specific setpoint analysis. The setpoints, as well as the response to a Loss of Voltage and Degraded Voltage test, shall include a single point verification that the trip occurs within the required delay time, as shown in Reference 1.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.3 (Continued)

The Frequency is based upon the assumption of a 24 month calibration interval for the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. SONGS Units 2 and 3 UFSAR, Section 8.3.
2. SONGS Units 2 and 3 UFSAR, Chapter 15.
3. 10 CFR 50, Appendix A, GDC 21.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The containment airborne radiation monitors will generate an isolation signal for the containment purge in the event of a LOCA. However, containment isolation is expected to occur on either a safety injection actuation system signal or a containment isolation actuation system signal prior to initiation on a CPIS signal on high radiation in containment. In addition, the calculations show that, following a fuel handling accident in containment due to the response time of the containment airborne radiation monitors there will be some release of radioactivity to the environment prior to isolation of the purge by the CPIS.

In order to calculate the off-site doses resulting from such a release, it was conservatively assumed that all of the airborne radioactivity resulting from a fuel handling accident in containment was released to the environment (i.e., the containment purge was not isolated following a fuel handling accident). The analysis showed that the 0-2 hour site boundary (exclusion area boundary [EAB]) thyroid dose and the 0-2 hour site boundary whole body (WB) dose would be below the Standard Review Plan (SRP) 15.7.4 limits of 75 rem thyroid and 6 rem WB (these SRP limits are based on 25 percent of the 10 CFR 100 limits).

General Design Criteria (GDC) 19 specifies that adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem WB, or its equivalent to any part of the body, for the duration of the accident. SRP 6.4 defines the dose-equivalent to the thyroid as 30 rem. The analysis demonstrated that the dose values are below those specified in GDC 19 as delineated by SRP 6.4.

(continued)

BASES (continued)

ACTIONS (continued)

Condition B applies to the failure of CRIS Manual Trip, Actuation Logic, and required gaseous radiation monitor channels in Mode 5 or 6, or when moving irradiated assemblies. The Required Actions are immediately taken to place one OPERABLE CREACUS train in the emergency mode, or to suspend positive reactivity additions, and movement of irradiated fuel assemblies. The Completion Time recognizes the fact that the radiation signals are the only Functions available to initiate control room isolation in the event of a fuel handling accident.

Required Action B.2.2 is modified by a note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value.

Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. Thus, performance of the CHANNEL CHECK guarantees that undetected overt channel failure is limited to 12 hours. Since the probability of two random failures in redundant channels in any 12 hour period is low, the CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. The CHANNEL CHECK

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.9.1 (continued)

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

SR 3.3.9.2

A CHANNEL FUNCTIONAL TEST is performed on the required control room radiation monitoring channel to ensure the entire channel will perform its intended function. As found and as left setpoints are recorded.

The Frequency of 92 days is based on plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 92 day interval is a rare event.

SR 3.3.9.3

Proper operation of the individual initiation relays is verified by de-energizing these relays during the CHANNEL FUNCTIONAL TEST of the Actuation Logic every 18 months. This will actuate the Function, operating all associated equipment. Proper operation of the equipment actuated by each train is thus verified.

The Frequency of 18 months is based on plant operating experience with regard to channel OPERABILITY, which demonstrates that failure of more than one channel of a given Function in any 18 month interval is a rare event.

A Note indicates this Surveillance includes verification of operation for each initiation relay.

SR 3.3.9.4

CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of an 18 month calibration interval is based on experience with the magnitude of equipment drift in this period.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.9.5

Every 18 months, a CHANNEL FUNCTIONAL TEST is performed on the manual CRIS actuation circuitry.

This test verifies that the trip push buttons are capable of opening contacts in the Actuation Logic as designed, de-energizing the initiation relays and providing Manual Trip of the function. 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 these components usually pass the Surveillance when performed at a Frequency of once every 18 months.

SR 3.3.9.6

This SDurveillance ensures that the train actuation response times are less than or equal to the maximum times assumed in the analyses. A time limit to isolate the control room is needed to ensure compliance with 10 CFR 50 Appendix A General Design Criterion 19. The 18 month frequency is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences. The response time is tested from the module input; i.e., the radiation detector response is not measured. Testing of the final actuating devices is included in the Surveillance. Response time testing acceptance criteria are included in Reference 4.

REFERENCES

1. SONGS Units 2 and 3 UFSAR, Chapter 15.
2. SCE Calculation A-92-NF-003.
3. 10 CFR 50, Appendix A, GDC 19.
4. Licensee Controlled Specification 3.3.100, "RPS/ESFAS Response Times."

B 3.3 INSTRUMENTATION

B 3.3.11 Post Accident Monitoring Instrumentation (PAMI)

BASES

BACKGROUND

The primary purpose of the PAMI is to display plant variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions for Design Basis Events.

The OPERABILITY of PAMI ensures that there is sufficient information available on selected plant parameters to monitor and assess plant status and behavior following an accident.

The availability of PAMI is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by plant specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97, Revision 2, (Ref. 2), as required by Supplement 1 to NUREG-0737, "TMI Action Items" (Ref. 3). The Updated Final Safety Analysis Report (UFSAR) (Ref. 4) provides design information and system capabilities.

Type A variables are included in this LCO because they provide the primary information required to permit the control room operator to take specific manually controlled actions, for which no automatic control is provided, that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the potential for causing a gross breach of the barriers to radioactivity release; and

(continued)

BASES (continued)

LCO (continued)

18. Auxiliary Feedwater (AFW) Flow

AFW Flow is provided to monitor operation of decay heat removal via the steam generators.

Each differential pressure transmitter provides an input to a control room indicator and the plant computer. Since the primary indication used by the operator during an accident is the control room indicator, the PAMI Specification deals specifically with this portion of the instrument channel.

AFW Flow is also used by the operator to verify that the AFW System is delivering the correct flow to each steam generator. However, the primary indication used by the operator to ensure an adequate inventory is steam generator level.

19. Containment Pressure (Narrow Range)

Containment Pressure is provided for verification of containment OPERABILITY.

20. Reactor Coolant System Subcooling Margin Monitor

The RCS subcooled Margin Monitor is required since it provides information to the operator regarding core cooling.

21. Pressurizer Safety Valve Position

Pressurizer Safety Valve Position is provided for proper position verification of the Pressurizer Safety Valves.

22. Containment Temperature

Containment Temperature is provided for verification of containment temperature.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.11.4

A CHANNEL CALIBRATION is performed every 18 months. CHANNEL CALIBRATION is a complete check of the instrument channel including the sensor. The Surveillance verifies the channel responds to the measured parameter within the necessary range and accuracy.

The Frequency is based upon operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift.

SR 3.3.11.5

A CHANNEL CALIBRATION is performed every 24 months for the Containment Area Radiation Monitor.

REFERENCES

1. SONGS Units 2 and 3 Regulatory Guide 1.97 Instrumentation Report #90065, Rev. 0, dated October 1, 1992.
2. Regulatory Guide 1.97, Revision 2.
3. NUREG-0737, Attachment 1.
4. UFSAR, Section 7.5.1.7.

LCO

The LCO on the source range monitoring channels ensures that adequate information is available to verify core reactivity conditions while shut down.

A minimum of two source range monitoring channels are required to be OPERABLE.

APPLICABILITY

In MODES 3, 4, and 5, with RTCBs open or the Control Element Assembly (CEA) Drive System not capable of CEA withdrawal, source range monitoring channels must be OPERABLE to monitor core power for reactivity changes. In MODES 1 and 2, and in MODES 3, 4, and 5, with the RTCBs shut and the CEAs capable of withdrawal, the Logarithmic Power Monitoring channels are addressed as part of the RPS in LCO 3.3.1, "Reactor Protective System (RPS) Instrumentation – Operating," and LCO 3.3.2, "Reactor Protective System (RPS) Instrumentation – Shutdown."

The requirements for source range neutron flux monitoring in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation." The source range nuclear instrumentation channels provide neutron flux coverage extending an additional one to two decades below the logarithmic channels for use during refueling, when neutron flux may be extremely low.

ACTIONS

A channel is inoperable when it does not satisfy the OPERABILITY criteria for the channel's function. These criteria are outlined in the LCO section of the Bases.

A.1 and A.2

With one required channel inoperable, it may not be possible to perform a CHANNEL CHECK to verify that the other required channel is OPERABLE. Therefore, with one or more required channels inoperable, the source range monitoring Function cannot be reliably performed. Consequently, the Required Actions are the same for one required channel inoperable or more than one required channel inoperable. The absence of reliable neutron flux indication makes it difficult to ensure SDM is maintained. Required Action A.1 is modified

(continued)

BASES (continued)

ACTIONS

A.1 and A.2 (continued)

by a note to indicate that normal plant control operations that individually add limited positive reactivity (e.g., temperature or boron fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided they are accounted for in the calculated SDM.

SDM must be verified periodically to ensure that it is being maintained. Both required channels must be restored as soon as possible. The initial Completion Time of 4 hours and once every 12 hours thereafter to perform SDM verification takes into consideration that Required Action A.1 eliminates many of the means by which SDM can be reduced. These Completion Times are also based on operating experience in performing the Required Actions and the fact that plant conditions will change slowly.

SURVEILLANCE REQUIREMENTS

SR 3.3.13.1

SR 3.3.13.1 is the performance of a CHANNEL CHECK on each required channel every 12 hours. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based upon the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.13.1 (continued)

Thus, the performance of CHANNEL CHECK ensures that undetected overt channel failure is limited to 12 hours.

Since the probability of two random failures in redundant channels in any 12 hour period is extremely low, CHANNEL CHECK minimizes the chance of loss of protective function due to failure of redundant channels. CHANNEL CHECK supplements less formal, but more frequent, checks of channel OPERABILITY during normal operational use of displays associated with the LCO required channels.

SR 3.3.13.2

A CHANNEL FUNCTIONAL TEST is performed every 92 days to ensure that the entire channel is capable of properly indicating neutron flux. Internal test circuitry is used to feed test signals into the signal processor to verify channel alignment. It is not necessary to test the detector, because generating a meaningful test signal is difficult; the detectors are of simple construction, and any failures in the detectors will be apparent as change in channel output. This Frequency is the same as that employed for the same channels in the other applicable MODES.

SR 3.3.13.3

SR 3.3.13.3 is the performance of a CHANNEL CALIBRATION. A CHANNEL CALIBRATION is performed every 24 months. The Surveillance is a complete check and readjustment of the source range channel from the preamplifier input through to the remote indicators. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive calibrations to ensure that the channel remains operational. Measurement error determination, setpoint error determination, and calibration adjustment must be performed consistent with the plant specific setpoint analysis. The channel shall be left calibrated consistent with the assumptions of the current plant specific setpoint analysis.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.13.3 (continued)

This SR is modified by a Note to indicate that it is not necessary to test the detector, because generating a meaningful test signal is difficult; the detectors are of simple construction, and any failures in the detectors will be apparent as change in channel output. This test interval is the same as that employed for the same channels in the other applicable MODES.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13.
2. SONGS Units 2 and 3 UFSAR, Chapter 7 and Chapter 15.

BASES (continued)

ACTIONS

C.1 and C.2 (continued)

The Completion Time of "prior to entering MODE 4" forces the evaluation prior to entering a MODE where temperature and pressure can be significantly increased. The evaluation for a mild violation is possible within several days, but more severe violations may require special, event specific stress analyses or inspections.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the Pressure /Temperature limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that requires this SR be performed only during RCS system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

NOTE: Any change in RCS temperature of less than 10 degrees F in any one hour period during normal operation is not considered an RCS heatup/ cooldown. This type of transient is determined by ASME III Code Class 1 stress calculations to be an insignificant transient in the contribution to the component fatigue usage factor.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3.1 Pressurizer Heatup and Cooldown Limits.

BASES

BACKGROUND

All components in the Reactor Coolant System are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in the UFSAR (Ref. 1). During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

During normal plant operations, primarily heatup and cooldown, some plant operating practices can induce pressurizer insurge and outsurge cycles which may effect the structural integrity of the pressurizer vessel. These insurge/outsurge cycles can introduce additional stress and fatigue loading to the lower region of the pressurizer.

Two components of the pressurizer are especially sensitive to thermal loading changes. They are the pressurizer spray line spray nozzle and the pressurizer surge line. The pressurizer spray line nozzle is subjected to thermal loadings which could limit the thermal fatigue life of a spray system to as low as 17.5 years. Of particular concern is the potential for flow stratification in the spray line during operation involving fewer than four RCPs. The horizontal piping configuration at the top of the spray line has been modified with a one-piece gooseneck arrangement, to promote filling the spray line and to reduce thermal cycling fatigue.

During RCP heatup and cooldown, both RCP P001 and P003 in the loop 1A/1B (with the pressurizer) should be operated whenever possible to ensure that the spray line remains filled. If this is not possible, throttling the main spray valve to keep the line filled is recommended. Thermal fatigue analyses of both the spray nozzle and spray piping using similar transient loadings were re-performed to the 1980 edition of the ASME Code Section III.

(continued)

BASES (continued)

LCO (continued)

of requiring both SGs to be capable (> 50% wide range water level) of transferring heat from the reactor coolant at a controlled rate. Forced reactor coolant flow is the required way to transport heat, although natural circulation flow provides adequate removal. A minimum of one running RCP meets the LCO requirement for one loop in operation.

The Note permits a limited period of operation without RCPs. All RCPs may be de-energized for ≤ 1 hour per 8 hour period. This means that natural circulation has been established. When in natural circulation, a reduction in boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained is prohibited because an even concentration distribution throughout the RCS cannot be ensured. Core outlet temperature is to be maintained at least 10°F below the saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

In MODES 3, 4, and 5, it is sometimes necessary to stop all RCPs or shutdown cooling (SDC) pump forced circulation (e.g., to change operation from one SDC train to the other, to perform surveillance or startup testing, to perform the transition to and from SDC System cooling, or to avoid operation below the RCP minimum net positive suction head limit). The time period is acceptable because natural circulation is adequate for heat removal, or the reactor coolant temperature can be maintained subcooled and boron stratification affecting reactivity control is not expected.

An OPERABLE loop consists of at least one RCP providing forced flow for heat transport and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, the heat load is lower than at power; therefore, one RCS loop in operation is adequate for transport and heat removal. A second RCS loop is required to be OPERABLE but not in operation for redundant heat removal capability.

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";

(continued)

BASES (continued)

APPLICABILITY (continued)

LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1

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

B.1

If restoration is not possible within 72 hours, the unit must be placed in MODE 4 within 12 hours. In MODE 4, the plant may be placed on the SDC System. The Completion Time of 12 hours is compatible with required operation 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 no RCS loop is in operation, except as provided in Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be immediately suspended. Action to restore one RCS loop to OPERABLE status and operation shall be initiated immediately and continued until one RCS loop is restored to OPERABLE status and operation. Suspending the introduction into the RCS of 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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

C.1 and C.2 (continued)

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 decay heat removal.

SR 3.4.5.1

This SR requires verification every 12 hours that the required number of RCS loops are in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.5.2

This SR requires verification every 12 hours that the secondary side water level in each SG is ≥ 50% wide range. An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the reactor coolant. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within the safety analyses assumptions.

SR 3.4.5.3

Verification that the required number of RCPs are OPERABLE ensures that the single failure criterion is met and that an additional RCS loop can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR, Section 15.3.

BASES (continued)

LCO (continued)

prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. The response of the RCS without the RCPs or SDC pumps depends on the core decay heat load and the length of time that the pumps are stopped. As decay heat diminishes, the effects on RCS temperature and pressure diminish. Without cooling by forced flow, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (pressure and temperature (P/T) limits or low temperature overpressure protection (LTOP) limits) must be observed and forced SDC flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping both RCPs or SDC pumps are to be limited to situations where:

a. Pressure and temperature increases can be maintained well within the allowable pressure (P/T limits and LTOP) and 10°F subcooling limits; or

b. An alternate heat removal path through the SGs is in operation.

Note 2 requires that either of the following two conditions be satisfied before an RCP may be started with any RCS cold leg temperature ≤ 256°F.

a. Pressurizer water volume is < 900 ft^3; or

b. Secondary side water temperature in each SG is < 100°F above each of the RCS cold leg temperatures.

Satisfying the above condition will preclude a large pressure surge in the RCS when the RCP is started.

An OPERABLE RCS loop consists of at least one OPERABLE RCP and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program and has the minimum water level specified in SR 3.4.6.2.

(continued)

BASES (continued)

ACTIONS

B.1 (continued)

reasonable, based on operating experience, to reach MODE 5 from MODE 4, with only one SDC train operating, in an orderly manner and without challenging plant systems.

C.1 and C.2

If no RCS loops or SDC trains are OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS loop or SDC train to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction into the RCS of 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 decay heat removal. The action to restore must continue until one loop or train is restored to operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one required loop or train is in operation. This ensures forced flow is providing heat removal. Verification includes flow rate, temperature, or pump status monitoring. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess RCS loop status. In addition, control room indication and alarms will normally indicate loop status.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

This SR requires verification every 12 hours of secondary side water level in the required SG(s) ≥ 50% (wide range). An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the reactor coolant. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS loop or SDC train can be placed in operation, if needed to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR, Section 15.4.1.4.

LCO

The purpose of this LCO is to require at least one of the SDC trains or RCS loops be OPERABLE and in operation with an additional SDC train or RCS loop OPERABLE or secondary side water level of each SG shall be ≥ 50% wide range. One SDC train or RCS loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. The second SDC or RCS loop train is normally maintained OPERABLE as a backup to the operating train/loop to provide redundant paths for decay heat removal. However, if the standby SDC train/RCS loop is not OPERABLE, a sufficient alternate method to provide redundant paths for decay heat removal is two SGs with their secondary side water levels ≥ 50% wide range. Should the operating SDC train/RCS loop fail, the SGs could be used to remove the decay heat.

Note 1 permits all RCPs and SDC pumps to be de-energized ≤ 1 hour per 8 hour period. The circumstances for stopping both SDC trains/RCS loops are to be limited to situations where pressure and temperature increases can be maintained well within the allowable pressure (pressure and temperature and low temperature overpressure protection) and 10°F subcooling limits, or an alternate heat removal path through the SG(s) is in operation.

This LCO is modified by a Note that prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.2 is maintained when forced flow is stopped because an even concentration distribution cannot be ensured. Core outlet temperature is to be maintained at least 10°F below saturation temperature, so that no vapor bubble would form and possibly cause a natural circulation flow obstruction. In this MODE, the SG(s) can be used as the backup for heat removal. To ensure their availability, the RCS loop flow path is to be maintained with subcooled liquid.

In MODE 5, it is sometimes necessary to stop all RCP or SDC forced circulation. This is permitted to change operation from one SDC train or RCS loop to the other, perform surveillance or startup testing, perform the transition to and from the SDC, or to avoid operation below the RCP minimum net positive suction head limit. The time period is acceptable because natural circulation is acceptable for decay heat removal, the reactor coolant temperature can be

(continued)

BASES (continued)

LCO (continued)

maintained subcooled, and boron stratification affecting reactivity control is not expected.

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

Note 3 allows one RCS loop to be inoperable for a period of up to 2 hours provided that the other RCS 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 4 requires that either of the following two conditions be satisfied before an RCP may be started:

a. Pressurizer water volume must be < 900 ft^3; or

b. Secondary side water temperature in each SG must be < 100°F above each of the RCS cold leg temperatures.

Satisfying either of the above conditions will preclude a low temperature overpressure event due to a thermal transient when the RCP is started.

Note 5 specifies that a containment spray (CS) pump may be used in place of a low pressure safety injection (LPSI) pump in either or both shutdown cooling trains to provide shutdown cooling (SDC) flow based on the calculated heat load of the core 24 hours after the reactor is sub-critical with the reactor coolant system (RCS) fully depressurized and vented in accordance with TS 3.4.12.

Note 6 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of SDC trains from operation when at least one RCP is in operation.

An OPERABLE SDC train is composed of an OPERABLE SDC pump and an OPERABLE SDC heat exchanger.

SDC pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE RCS loop consists of at least one OPERABLE RCP and an OPERABLE SG. An OPERABLE SG can perform as a heat sink when it has

(continued)

BASES (continued)

LCO (continued)

an adequate water level and is OPERABLE in accordance with the SG Tube Surveillance Program.

An OPERABLE RCS loop consists of at least one RCP providing forced flow for heat transport and an SG that is OPERABLE in accordance with the Steam Generator Tube Surveillance Program. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation to remove decay heat from the core and to provide proper boron mixing. One SDC train/RCS loop provides sufficient circulation for these purposes.

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 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If the required SDC train/RCS loop is inoperable and any SGs have secondary side water levels < 50% wide range, redundancy for heat removal is lost. Action must be initiated immediately to restore a second SDC train/RCS loop to OPERABLE status or to restore the water level in the required SGs. Either Required Action A.1 or Required Action A.2 will restore redundant decay heat removal paths. The immediate Completion Times reflect the importance of maintaining the availability of two paths for decay heat removal.

B.1 and B.2

If no SDC train/RCS loop is in operation, except as permitted in Note 1, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.2 must be

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

suspended. Action to restore one SDC train/RCS loop to operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.2 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 decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that at least one SDC train/RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify operation is within safety analyses assumptions. In addition, control room indication and alarms will normally indicate loop status.

The SDC/RCS flow is established to ensure that core outlet temperature is maintained sufficiently below saturation to allow time for swap over to the standby SDC train/RCS loop should the operating train be lost.

SR 3.4.7.2

Verifying the SGs are OPERABLE by ensuring their secondary side water levels are ≥ 50% wide range ensures that redundant heat removal paths are available if the second SDC train/RCS loop is inoperable. The Surveillance is required to be performed when the LCO requirement is being met by use of the SGs. If both SDC trains are OPERABLE and one SDC train is in operation, this SR is not needed. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require a minimum of two SDC trains be OPERABLE and at least one of these trains be in operation. An OPERABLE train is one that is capable of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the SDC System unless forced flow is used. A minimum of one running SDC pump meets the LCO requirement for one train in operation. An additional SDC train is required to be OPERABLE to meet the single failure criterion.

Note 1 permits the SDC pumps to be de-energized for ≤ 15 minutes when switching from one train to another. The circumstances for stopping both SDC pumps are to be limited to situations when the outage time is short and the core outlet temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.2 is maintained or draining operations when SDC forced flow is stopped.

Note 2 specifies the pump providing shutdown cooling may be de-energized for up to 1 hour per 8 hour period provided 1) no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SDM of LCO 3.1.2, and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

Note 3 allows one SDC train to be inoperable for a period of 2 hours provided that the other train is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable train during the only time when these tests are safe and possible.

Note 4 specifies that a containment spray pump may be used in place of a low pressure safety injection pump in either or both shutdown cooling trains to provide shutdown cooling flow provided the reactor has been sub-critical for a period greater than 24 hours and the reactor coolant system is fully depressurized and vented in accordance with TS 3.4.12.1.

(continued)

BASES (continued)

LCO (continued)	An OPERABLE SDC train is composed of an OPERABLE SDC pump capable of providing forced flow to an OPERABLE SDC heat exchanger, along with the appropriate flow and temperature instrumentation for control, protection, and indication. SDC pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.
APPLICABILITY	In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the SDC System. Operation in other MODES is covered by: LCO 3.4.4, "RCS Loops – MODES 1 and 2"; LCO 3.4.5, "RCS Loops – MODE 3"; LCO 3.4.6, "RCS Loops – MODE 4"; LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled"; LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation – High Water Level" (MODE 6); and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation – Low Water Level" (MODE 6).
ACTIONS	<u>A.1</u> If the required SDC train is inoperable, redundancy for heat removal is lost. Action must be initiated immediately to restore a second train to OPERABLE status. The Completion Time reflects the importance of maintaining the availability of two paths for heat removal. <u>B.1 and B.2</u> If no SDC train is OPERABLE or in operation, except as provided in Note 1 or in Note 2, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.2 must be suspended. Action to restore one SDC train to OPERABLE status and operation must be initiated immediately. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.2 is required to assure continued safe

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

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 Time reflects the importance of maintaining operation for decay heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that at least one SDC train is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing decay heat removal. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess degradation and verify operation is within safety analyses assumptions.

SR 3.4.8.2

Verification that the required number of trains are OPERABLE ensures that redundant paths for heat removal are available and that additional trains can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and indicated power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. UFSAR, Section 5.4.7.

B 3.4 REACTOR COOLANT SYSTEMS (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water volume, the required heaters and their heater controls. Pressurizer safety valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves."

The maximum water volume limit has been established to ensure that a liquid to vapor interface exists to permit RCS pressure control, using the sprays and heaters during normal operation and proper pressure response for anticipated design basis transients. The water volume limit serves two purposes:

a. Pressure control during normal operation maintains subcooled reactor coolant in the loops and thus in the preferred state for heat transport; and

b. By restricting the volume to a maximum, expected transient reactor coolant volume increases (pressurizer insurge) will not cause excessive volume changes that could result in degraded ability for pressure control.

The maximum water volume limit permits pressure control equipment to function as designed. The limit preserves the steam space during normal operation, thus, both sprays and heaters can operate to maintain the design operating pressure. The volume limit also prevents filling the pressurizer (water solid) for anticipated design basis transients, thus ensuring that pressure relief devices

(continued)

BASES (continued)

BACKGROUND (continued)

(Pressurizer safety valves) can control pressure by steam relief rather than water relief. If the volume limits were exceeded prior to a transient that creates a large pressurizer insurge volume leading to water relief, the maximum RCS pressure might exceed the Safety Limit of 2750 psia.

The requirement to have two groups of pressurizer heaters ensures that RCS pressure can be maintained. These heaters are powered from buses 2B04 and 2B06. The pressurizer heaters maintain RCS pressure to keep the reactor coolant subcooled. Inability to control RCS pressure during natural circulation flow could result in loss of single phase flow and decreased capability to remove core decay heat.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. No safety analyses are performed in lower MODES. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensable gases normally present.

Safety analyses presented in the UFSAR do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 1), is the reason for their inclusion.
Section II.E.3.1 of Ref. 1 requires that pressurizer heaters and associated controls necessary to establish and maintain natural circulation in hot standby conditions be powered from either the offsite power source or the emergency power source (when offsite power is not available), and that the heaters and their controls be connected to the emergency buses in a manner that will provide redundant power supply capability. The intent is to keep the reactor coolant in a subcooled condition with natural circulation at hot, high pressure conditions for an undefined, but extended, time

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

period after a loss of offsite power. While loss of offsite power is a coincident occurrence assumed in the accident analyses, maintaining hot, high pressure conditions over an extended time period is not evaluated in the accident analyses.

The pressurizer satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirement for the pressurizer to be OPERABLE with water level ≤ 57% ensures that a steam bubble exists. Limiting the maximum operating water volume preserves the steam space for pressure control. The LCO has been established to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW. The heaters are powered from buses 2B04 and 2B06. The exact design value of 150 kW is derived from the use of three heaters rated at 50 kW each. The amount needed to maintain pressure is dependant on the ambient heat losses. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide subcooling margin to saturation can be obtained in the loops.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, Applicability has been designated for MODES 1 and 2. The Applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup. The LCO does not apply to MODE 5 (Loops Filled) because LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," applies. The LCO does not apply to MODES 5 and 6 with partial loop operation.

(continued)

BASES (continued)

APPLICABILITY (continued)

In MODES 1, 2, and 3, there is the need to maintain the availability of pressurizer heaters. In the event of a loss of offsite power, the initial conditions of these MODES gives the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Shutdown Cooling System is in service and therefore the LCO is not applicable.

ACTIONS

A.1 and A.2

With pressurizer water volume not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the plant out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses.

Six hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Further pressure and temperature reduction to MODE 4 brings the plant to a MODE where the LCO is not applicable. The 12 hour time to reach the nonapplicable MODE is reasonable based on operating experience for that evolution.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

(continued)

BASES (continued)

ACTIONS (continued)

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

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

SR 3.4.9.2

The Surveillance is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. (This may be done by measuring circuit current and voltage to calculate the heater kW capacity.) The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The purpose of the two spring loaded pressurizer safety valves is to provide RCS overpressure protection. Operating in conjunction with the Reactor Protection System, two valves are used to ensure that the Safety Limit (SL) of 2750 psia is not exceeded for analyzed transients during operation in MODES 1, 2 and 3. During MODE 4, MODE 5, and MODE 6 with the reactor pressure vessel head on, overpressure protection is provided by operating procedures and LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System." For these conditions, American Society of Mechanical Engineers (ASME) requirements are satisfied with one safety valve.

The self actuated pressurizer safety valves are designed in accordance with the requirements set forth in the ASME, Boiler and Pressure Vessel Code, Section III (Ref. 1). The as-found lift pressure is 2500 psia, +3% or -2% (Ref. 4). Following testing, pressurizer safety valves shall be set within ±1% of the specified setpoint. The safety valves discharge steam from the pressurizer to a quench tank located in the containment (Ref. 2). The discharge flow is indicated by an increase in temperature downstream of the safety valves and by an increase in the quench tank temperature and level.

The as-found upper pressure tolerance limit of +3% is based on limiting the RCS pressure to 110% of design pressure for infrequent design basis events and 120% of design pressure for limiting faulted events. The as-found lower pressure tolerance limit of -2% is based on ensuring a reactor trip occurs on high pressurizer pressure prior to safety valve actuation (Ref. 4). The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% or 120% of design pressure, depending on the frequency classification of the design basis event. The consequences of exceeding the ASME pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

All accident analyses in the UFSAR that require safety valve actuation assume operation of both pressurizer safety valves to limit increasing reactor coolant pressure (Ref. 3). The overpressure protection analysis is also based on operation of both safety valves and assumes that the valves open at the high range of the setting (2500-psia system design pressure plus 1%). These valves must accommodate pressurizer insurges that could occur during a startup, rod withdrawal, ejected rod, loss of main feedwater, or main feedwater line break accident. The combined relief capacity of these valves is sufficient to limit the System pressure to within its Safety Limit of 2750 psia following a complete loss of turbine generator load while operating at RATED THERMAL POWER and assuming no reactor trip until the first Reactor Protective System trip setpoint (Pressurizer Pressure-High) is reached (i.e., no credit is taken for a direct reactor trip on the loss of turbine) and also assuming no operation of the steam dump valves. The startup accident establishes the minimum safety valve capacity. The startup accident is assumed to occur at < 15% power. Single failure of a safety valve is neither assumed in the accident analysis nor required to be addressed by the ASME Code. Compliance with this specification is required to ensure that the accident analysis and design basis calculations remain valid.

The pressurizer safety valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

The two pressurizer safety valves are set to open at the RCS design pressure (2500 psia) and within the ASME specified tolerance to avoid exceeding the maximum RCS design pressure SL, to maintain accident analysis assumptions, and to comply with ASME Code requirements. The as-found upper pressure tolerance limit of +3% is based on limiting the RCS pressure to 110% of design pressure for infrequent design basis events and 120% of design pressure for limiting faulted events. The as-found lower pressure tolerance limit of -2% is based on ensuring a reactor trip occurs on high pressurizer pressure prior to safety valve actuation (Ref. 4). The limit protected by this specification is the reactor coolant pressure boundary (RCPB) SL of 110% or 120% of design pressure. Inoperability of one or both valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The 6 hours allowed is reasonable, based on operating experience, to reach MODE 3 from full power without challenging plant systems. Similarly, the 12 hours allowed is reasonable, based on operating experience, to reach MODE 4 without challenging plant systems. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the inservice testing program. Pressurizer safety valves are to be tested one at a time and in accordance with the requirements of Section XI of the ASME Code (Ref. 1), which provides the activities and the Frequency necessary to satisfy the SRs. No additional requirements are specified.

The as-found pressurizer safety valve tolerance is +3% or -2% for OPERABILITY. Following testing, pressurizer safety valves shall be set within ±1% of the specified setpoint.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III, Section XI (OM 1987 Part 1).
2. UFSAR, Section 5.4
3. UFSAR, Section 15.
4. ABB Letter No. ST-96-623 dated December 19, 1996; subject: Transmittal and Completion of the SCE SONGS 2/3 PSV Tolerance Study.

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 or A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 9 months, but may be extended up to a maximum of 24 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 24 month Frequency is required in 10 CFR 50.55a(g) (Ref. 8), as contained in the Inservice Testing Program, is within the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 9), and is based on the need to perform the Surveillance under conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure capability for tight reseating. For the valves in Table 3.4.14.1 Section B, forward flow in excess of the seat leakage criteria constitutes opening the valve by flow.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

PIVs disturbed (opened by flow) in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 48 hours after the valve has been reseated. Within 48 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complimentary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months. In addition, this Surveillance is not required to be performed on the SDC System when the SDC System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the SDC shutdown cooling flow path must be leakage rate tested after SDC is secured and stable unit conditions and the necessary differential pressures are established.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A, Section V, GDC 55.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.
5. NUREG-0677, May 1980.
6. UFSAR, Section 5.4
7. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWV-3423 (e).
8. 10 CFR 50.55a(g).
9. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWV-3422.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND	The Code of Federal Regulations, 10 CFR 100 (Ref. 1) specifies the maximum dose to the whole body and the thyroid an individual at the site boundary can receive for 2 hours during an accident. The limits on specific activity ensure that the doses are held within the 10 CFR 100 limits during analyzed transients and accidents. The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident. The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized based on generic parametric evaluations of offsite radioactivity dose consequences for typical site locations. The parametric evaluations showed the potential offsite dose levels for a generic SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumed a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.
APPLICABLE SAFETY ANALYSES	The LCO limits on the specific activity of the reactor coolant ensure that the resulting 2 hour doses at the site boundary will not exceed the 10 CFR 100 dose guideline limits following an SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant is at the LCO limits and an existing reactor coolant steam generator (SG) tube leakage rate of 0.5 gpm per steam generator (1 gpm total). The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	this analysis is used to assess changes to the facility that could affect RCS specific activity as they relate to the acceptance limits. The rise in pressure in the ruptured SG causes radioactively contaminated steam to discharge to the atmosphere through the atmospheric dump valves or the main steam safety valves. The atmospheric discharge stops when the turbine bypass to the condenser removes the excess energy to rapidly reduce the RCS pressure and close the valves. The unaffected SG removes core decay heat by venting steam until the cooldown ends. The safety analysis shows the radiological consequences of an SGTR accident are within the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1 for more than 48 hours. The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of an SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits. RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.
LCO	The specific iodine activity in the primary coolant is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity of radionuclides other than iodine in the primary coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary during the Design Basis Accident (DBA) will be within the allowed thyroid dose criterion. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be within the allowed whole body dose criterion.

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS – Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA);

b. Control Element Assembly (CEA) ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are two phases of ECCS operation: injection and recirculation. In the injection phase, all injection is initially added to the Reactor Coolant System (RCS) via the cold legs. After the refueling water storage tank (RWST) has been depleted, the ECCS recirculation phase is entered as the ECCS suction is automatically transferred to the containment sump. During the later portions of the recirculation phase, the injection flow is split approximately equally between the hot and cold legs.

Two redundant, 100% capacity trains are provided. In MODES 1, 2, and 3, with pressurizer pressure ≥ 400 psia, each train consists of high pressure safety injection (HPSI) and low pressure safety injection (LPSI). In MODES 1, 2, and 3, with pressurizer pressure ≥ 400 psia, both trains must be OPERABLE. This ensures that 100% of the core cooling requirements can be provided in the event of a single active failure.

A suction header supplies water from the RWST or the containment sump to the ECCS pumps. Separate piping supplies each train. The discharge headers from each HPSI pump divide into four supply lines. Both HPSI trains feed

(continued)

BACKGROUND (continued)

into each of the four injection lines. The discharge header from LPSI pumps divides into two supply lines, each feeding the injection line to two RCS cold legs. Orifices are set to balance the flow to the RCS. This flow balance directs sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

While not credited in the ECCS analysis, the charging pumps take suction from the RWST or the Boric Acid Makeup Tanks (BAMUs) on a safety injection actuation signal (SIAS) and discharge directly to the RCS through a common header. The normal supply source of the charging pumps is isolated on SIAS.

During low temperature conditions in the RCS, limitations are placed on the maximum number of HPSI pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

During a limiting large break LOCA, RCS pressure will decrease to < 200 psia in < 20 seconds. The safety injection (SI) systems are actuated upon receipt of an SIAS. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the diesel generators (DGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading,and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive safety injection tanks (SITs) covered in LCO 3.5.1, "Safety Injection Tanks (SITs)," and the RWST covered in LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

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APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria, established by 10 CFR 50.46 (Ref. 2) for ECCSs, will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;
d. Core is maintained in a coolable geometry; and
e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following a steam line break (SLB) and ensures that containment temperature limits are met.

Both HPSI and LPSI subsystems are assumed to be OPERABLE in the large break LOCA analysis at full power (Ref. 3). This analysis establishes a minimum required runout flow for the HPSI and LPSI pumps, as well as the maximum required response time for their actuation. The HPSI pumps are credited in the small break LOCA analysis. This analysis establishes the flow and discharge head requirements at the design point for the HPSI pump. The SGTR and SLB analyses also credit the HPSI pumps, but are not limiting in their design.

The large break LOCA event with a loss of offsite power and a single failure (disabling one ECCS train) establishes the OPERABILITY requirements for the ECCS. During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control element assembly (CEA) insertion during small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

On smaller breaks, RCS pressure will stabilize at a value dependent upon break size, heat load, and injection flow.

The LCO ensures that an ECCS train will deliver sufficient water to match decay heat boiloff rates soon enough to minimize core uncovery for a large LOCA. It also ensures that the HPSI pump will deliver sufficient water during a small break LOCA, and will provide sufficient boron to maintain the core subcritical following an SLB. The SGs continue to serve as the heat sink providing core cooling during a small break LOCA.

ECCS – Operating satisfies Criterion 3 of the NRC Policy Statement.

LCO

In MODES 1, 2, and 3, with pressurizer pressure ≥ 400 psia, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming there is a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1 and 2, and in MODE 3 with pressurizer pressure ≥ 400 psia, an ECCS train consists of a HPSI subsystem and a LPSI subsystem.

Each train includes the piping, instruments, and controls to ensure the availability of an OPERABLE flow path capable of taking suction from the RWST on a SIAS and automatically transferring suction to the containment sump upon a recirculation actuation signal (RAS).

During an event requiring ECCS actuation, a flow path is provided to ensure an abundant supply of water from the RWST to the RCS, via the HPSI and LPSI pumps and their respective supply headers, to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply part of its flow to the RCS hot legs via the shutdown cooling (SDC) suction nozzles.

(continued)

LCO (continued)

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure ≥ 400 psia, the ECCS OPERABILITY requirements for the limiting Design Basis Accident (DBA) large break LOCA are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The HPSI pump performance is based on the small break LOCA, which establishes the pump performance curve and has less dependence on power. The requirements of MODES 2, and 3 with RCS pressure ≥ 400 psia, are bounded by the MODE 1 analysis.

The ECCS functional requirements of MODE 3, with RCS pressure < 400 psia, and MODE 4 are described in LCO 3.5.3, "ECCS – Shutdown."

In MODES 5 and 6, unit conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops-MODE 5, Loops Not Filled."

MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation – High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation – Low Water Level."

ACTIONS

A.1 and B.1

An ECCS train is inoperable if it is not capable of delivering the design flow to the RCS. The individual components are inoperable if they are not capable of performing their design function, or if supporting systems are not available.

(continued)

ACTIONS

A.1 and B.1 (continued)

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of each of Condition A and Condition B is to maintain a combination of OPERABLE equipment such that 100% of the ECCS flow equivalent to 100% of a single OPERABLE train remains available. This allows increased flexibility in plant operations when components in opposite trains are inoperable.

Each of Condition A and Condition B includes a combination of OPERABLE equipment such that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available.

Condition A addresses the specific condition where the only affected ECCS subsystem is a single LPSI subtrain. The availability of a least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is implicit in the definition of Condition A.

If LCO 3.5.2 requirements are not met due only to the existence of Condition A, then the inoperable LPSI subtrain components must be returned to OPERABLE status within 7 days of discovery of Condition A. A Configuration Risk Management Program (CRMP) defined in Administrative Controls section 5.5.2.14 is implemented in the event of Condition A. This 7-day Completion Time is based on the findings of the deterministic and probabilistic analysis that are discussed in Reference 6. Seven days is a reasonable amount of time to perform many corrective and preventative maintenance items on the affected LPSI subtrain. Reference 6 concluded that the overall risk impact of this Completion Time was either risk-beneficial or risk-neutral.

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ACTIONS

A.1 and B.1 (continued)

Condition B addresses other scenarios where the availability of at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train exists but the full requirements of LCO 3.5.2 are not met. If Condition B exists, then inoperable components must be restored such that Condition B does not exist within 72 hours of discovery. The 72 hour Completion Time is based on an NRC reliability study (Ref. 4) and is a reasonable amount of time to effect many repairs.

An event accompanied by a loss of offsite power and the failure of an emergency DG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown that the impact with one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 5 describes situations in which one component, such as a shutdown cooling total flow control valve, can disable both ECCS trains. With one or more components inoperable, such that 100% of the equivalent flow to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analyses. In such a situation, LCO 3.0.3 must be immediately entered.

C.1 and C.2

If the inoperable train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and pressurizer pressure reduced to < 400 psia within 12 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1 and 3.5.2.2

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 removing power or by key locking the control in the correct position ensures that the valves cannot be inadvertently misaligned or change position as the result of an active failure. These valves are of the type described in Reference 5, which can disable the function of both ECCS trains and invalidate the accident analysis. SR 3.5.2.2 verification of the proper positions of the Containment Emergency Sump isolation valves and ECCS pumps/containment spray pumps miniflow valves ensures that ECCS operability and containment integrity are maintained. Securing these valves in position with power available will provide additional assurance that these valves will operate on a RAS. A 12 hour Frequency is considered reasonable in view of other administrative controls ensuring that a mispositioned valve is an unlikely possibility.

SR 3.5.2.3

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 valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions 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 procedural control and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.4

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 ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. 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 SIAS or during SDC. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the adequacy of the procedural controls governing system operation.

SR 3.5.2.5

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the unit safety analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.6

Deleted

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.7, SR 3.5.2.8, and SR 3.5.2.9

These SRs demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SIAS and/or an actual or simulated RAS as appropriate to each valve, that each ECCS pump starts on receipt of an actual or simulated SIAS, and that the LPSI pumps stop on receipt of an actual or simulated RAS. As a part of SR 3.5.2.8, subgroup relay K108, which starts the pumps on a safety injection actuation signal and disables non-safety related pump trips on low suction pressure and high pressurizer level, needs to be tested to verify these trips are disabled. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.10

Periodic inspection of the containment sump ensures that it is unrestricted and stays in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during an outage, on the need to have access to the location. This Frequency is sufficient to detect abnormal degradation and is confirmed by operating experience.

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REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.
2. 10 CFR 50.46.
3. UFSAR, Section 6.3, 15.6.3, and 15.10.6.3.
4. NRC Memorandum to V. Stello, Jr., from R. L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
5. IE Information Notice No. 87-01, January 6, 1987.
6. CE NPSD-995, "CEOG Joint Applications Report for Low Pressure Safety Injection System AOT Extension," May 1995.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on an automatic isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, pipe caps, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analysis. One of these barriers may be a closed system.

Containment isolation occurs upon receipt of a high containment pressure signal. The containment isolation signal closes automatic containment isolation valves in fluid penetrations not required for operation of Engineered Safety Feature systems in order to prevent leakage of radioactive material. Upon actuation of safety injection, automatic containment isolation valves also isolate systems not required for containment or RCS heat removal. Other penetrations are isolated by the use of valves in the closed position or blind flanges. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated in the event of a release of radioactive material to containment atmosphere from the RCS following a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analysis. Therefore, the OPERABILITY requirements provide assurance that containment leakage rates assumed in the accident analysis will not be exceeded.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2 (continued)

barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetrations isolated in accordance with Required Action A.1, the valve used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within the 4 hour Completion Time. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the valves are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides appropriate actions.

(continued)

BASES (continued)

ACTIONS (continued)

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

In the event one or more containment purge valves in one or more penetration flow paths are not within the purge valve leakage limits, purge valve leakage must be restored to within limits, or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve with resilient seals, a closed manual valve with resilient seals, or a blind flange. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.6. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, that those isolation devices outside Containment capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

For the containment purge valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.3.6 must be performed at least once every 184 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.6, 184 days, is based on an NRC initiative, Generic Issue B-20 (Ref. 3).

(continued)

BASES

ACTIONS

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

Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 184 days was chosen and has been shown to be acceptable based on operating experience.

E.1, E.2, F.1, and F.2

The completion time (CT) for Section D.1 and D.2 valves is based on restoring the ESF System to OPERABLE status. Therefore, the appropriate completion time is based on the specific ESF System Requirements.

The second completion times for Section D.1 and D.2 Valves are different based on the results of specific risk evaluations for valves that may be secured open. The second completion times are for restoring complete (open and close) operability of the valves.

Section D.1 and D.2 valves may be placed into the required action condition to allow periodic testing and testing following maintenance.

G.1 and G.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 42 inch containment purge valve is required to be verified sealed closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 3), related to containment purge valve use during unit operations. This SR is not required to be met while in Condition D of this LCO. This is reasonable since the penetration flow path would be isolated.

SR 3.6.3.2

This SR ensures that the minipurge valves are closed as required or, if open, open for an allowable reason. The SR is not required to be met when the purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The minipurge valves are capable ofclosing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, that those valves outside containment and capable of being mispositioned are in the correct position. Since

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

verification of valve position for valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. Valves that are open under administrative controls are not required to meet the SR during the time the valves are open.
The first Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small. The second note specifies that SR 3.0.4 is not applicable.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the containment boundary is within design limits. For valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate, since these valves and flanges are operated under administrative controls and the probability of their misalignment is low. Valves that are open under administrative controls are not required to meet the SR during the time that they are open.

The first Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in their proper position, is small The second note specifies that SR 3.0.4 is not applicable.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)	occurred while the containment internal pressure was at the LCO value of 1.5 psig, transient pressure analysis shows that a total pressure of 58.7 psig is calculated. The higher pressure increase is caused by the effect of heating the greater air mass present at the initial conditions of 1.5 psig. This value is still below the design value of 60 psig. The containment was also designed for an internal pressure equal to 5.0 psig below external pressure in order to withstand the resultant pressure drop from an accidental actuation of the Containment Spray System. The LCO limit of -0.3 psig ensures that operation within the design limit of -5.0 psig is maintained. The maximum calculated external pressure that would occur as a result of an inadvertent actuation of the Containment Spray System is 4.2 psig. Containment pressure satisfies Criterion 2 of the NRC Policy Statement.
LCO	Maintaining containment pressure less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative pressure differential following the inadvertent actuation of the Containment Spray System.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analysis are maintained, the LCO is applicable in MODES 1, 2, 3, and 4. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

during an MSLB). Both results are within the design. (See the Bases for Specifications 3.6.4, "Containment Pressure," and 3.6.5, "Containment Air Temperature," for a detailed discussion.) The analyses and evaluations assume a power level of 102% RTP, one containment spray train and one containment cooling train operating, and initial (pre-accident) conditions of 120°F and 14.7 psia. The analyses also assume a response time delayed initiation in order to provide a conservative calculation of peak containment pressure and temperature responses.

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation reduces the containment pressure to -4.2 psig due to the sudden cooling effect in the interior of the air tight containment. Additional discussion is provided in the Bases for Specification 3.6.4.

The modeled Containment Spray System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-High pressure setpoint coincident with an SIAS to achieve full flow through the containment spray nozzles. The Containment Spray System total response time includes diesel generator startup (for loss of offsite power), block loading of equipment, containment spray pump startup, and spray line filling (Ref. 2).

The performance of the containment cooling train for post accident conditions is given in Reference 2. The result of the analysis is that each train can provide 50% of the required peak cooling capacity during the post accident condition. The train post accident cooling capacity under varying containment ambient conditions, required to perform the accident analyses, is also shown in Reference 2.

The modeled Containment Cooling System actuation from the containment analysis is based upon the unit specific response time associated with exceeding the CCAS to achieve full Containment Cooling System air and CCW System water flow.

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

During a DBA, a minimum of two containment cooling trains or two containment spray trains, or one of each, is required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). Additionally, one containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and two containment cooling units must be OPERABLE. Therefore, in the event of an accident, the minimum requirements are met, assuming that the worst case single active failure occurs.

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and automatically transferring suction to the containment sump.

Each Containment Cooling System includes demisters, cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature, requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray and Containment Cooling systems are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 7 days. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. A Configuration Risk Management (CRMP) defined in the Administrative Controls Section 5.5.2.14 is implemented in the event of

(continued)

ACTIONS

A.1 (continued)

Condition A. The 7-day Completion Time is based on the findings of the deterministic and probabilistic analysis that was reviewed and approved in Reference 5. Seven days is a reasonable amount of time to perform many corrective and preventive maintenance items on the affected Containment Spray Train.

The 14 day portion of the Completion Time is based upon engineering judgement. It takes into account the low probability of coincident entry into two conditions in this Specification coupled with the low probability of an accident occurring during this time. 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 and B.2

If the inoperable containment spray train 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 4 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 4 allows additional time for the restoration of the containment spray train and is reasonable when considering that the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one required containment cooling train inoperable, the inoperable containment cooling train must be restored to OPERABLE status within 7 days. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System and the low probability of a DBA occurring during this period.

(continued)

ACTIONS (continued)

C.1 (continued)

The 14 day portion of the Completion Time is based upon engineering judgement. It takes into account the low probability of coincident entry into two conditions in this Specification coupled with the low probability of an accident occurring during this time. 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.

D.1

With two required containment cooling trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, the iodine removal function of the Containment Spray System, and the low probability of a DBA occurring during this period.

E.1

With two containment spray trains or any combination of three or more Containment Spray System and Containment Cooling System trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

F.1 and F.2

If the Required Actions and associated Completion Times of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least

(continued)

BASES (continued)

ACTIONS (continued)

F.1 and F.2 (continued)

MODE 3 within 6 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these were verified to be in the correct position prior to being secured. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation. Rather, it involves verifying, that those valves outside containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.6.1.2

Operating each containment cooling train fan unit for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected and corrective action taken. The 31 day Frequency of this SR was developed considering the known reliability of the fan units and controls, the two train redundancy available, and the low probability of a significant degradation of the containment cooling train occurring between surveillances and has been shown to be acceptable through operating experience.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.1.3

Verifying a CCW System flow rate of ≥ 2000 gpm to each cooling unit provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 2). Also considered in selecting this Frequency were the known reliability of the CCW System, the two train redundancy, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.6.1.4

Verifying that the containment spray header piping is full of water to within 10 feet of the lowest spray ring minimizes the time required to fill the header. This ensures that spray flow will be admitted to the containment atmosphere within the time frame assumed in the containment analysis. The 24 month Frequency is based on the static nature of the fill header and the low probability of a significant degradation of water level in the piping occurring between surveillances.

SR 3.6.6.1.5 and SR 3.6.6.1.6

These SRs verify that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation signal. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The surveillance of containment sump isolation valves is also required by SR 3.5.2.5. A single surveillance may be used to satisfy both requirements.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.1.7

This SR verifies that each containment cooling train actuates upon receipt of an actual or simulated actuation signal. The 24 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See SR 3.6.6.1.6 and SR 3.6.6.1.7, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.1.8

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. Performance of this SR demonstrates that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test at 10 year intervals is considered adequate to detect obstruction of the spray nozzles.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 38, GDC 39, GDC 40, GDC 41, GDC 42, and GDC 43.
2. SONGS Units 2 and 3 UFSAR, Section 6.2.
3. SONGS Units 2 and 3 UFSAR, Section 15.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. CE-NPSD-1045, "Joint Applications Report, Modifications to the Containment Spray System, and the Low Pressure Safety Injection System Technical Specifications," March 1998.

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B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Containment Dome Air Circulators

BASES

BACKGROUND

The containment dome air circulators reduce the potential for breach of containment due to a hydrogen oxygen reaction by providing a uniformly mixed post accident containment atmosphere.

The post accident dome air circulator is an Engineered Safety Feature and is designed to withstand a loss of coolant accident (LOCA) without loss of function. The system has two independent trains, each of which consists of two 100% capacity dome air circulation fans, motors, and controls. Each train is capable of providing 74,000 cfm, with each fan providing the minimum required 37,000 cfm. The two trains are initiated automatically on a containment cooling actuation signal (CCAS) or can be manually started from the control room. Each train is powered from a separate emergency power supply. Since each train can provide 100% of the mixing requirements with at least one fan operable, the system will provide its design function with a limiting single active failure.

The dome air circulator accelerates the air mixing process between the upper dome space of the containment atmosphere during LOCA operations. It also prevents any hot spot air pockets during the containment cooling mode and avoids any hydrogen concentration in pocket areas.

Hydrogen mixing within the containment is also accomplished by the Containment Spray System, the containment emergency fan coolers, and the containment internal structure design, which permits convective mixing and prevents entrapment. The dome air circulator, operating in conjunction with the Containment Spray System and the emergency fan coolers, prevents localized accumulations of hydrogen from exceeding the flammability limit of 4.1 volume percent (v/o).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The dome air circulators mix the containment atmosphere to provide a uniform hydrogen concentration.

Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to Containment Spray System and Emergency Core Cooling Systems solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 1 are used to maximize the amount of hydrogen calculated.

The dome air circulators satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two dome air circulator trains must be OPERABLE, with power to each from an independent, safety related power supply. Each train consists of two fans with their own motors and controls and is automatically initiated by a CCAS. A train is OPERABLE with one OPERABLE fan.

Operation with at least one dome air circulator train provides the mixing necessary to ensure uniform hydrogen concentration throughout containment.

APPLICABILITY

In MODES 1 and 2, the two dome air circulator trains ensure the capability to prevent localized hydrogen concentrations above the flammability limit of 4.1 v/o in containment, assuming a worst case single active failure.

(continued)

BASES (continued)

APPLICABILITY (continued)

In MODE 3 or 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the dome air circulator is low. Therefore, the dome air circulators are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA or main steam line break are low due to the pressure and temperature limitations of these MODES. Therefore, the dome air circulators are not required in these MODES.

ACTIONS

A.1

With one dome air circulator train inoperable, the inoperable train must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on the availability of the other dome air circulator train, the small probability of a LOCA or SLB occurring, and the availability of the Containment Spray System and hydrogen monitors.

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one dome air circulator train is inoperable. This allowance is based on the availability of the other dome air circulator train and the small probability of a LOCA or SLB occurring.

B.1 and B.2

With two dome air circulators inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within

(continued)

BASES (continued)

ACTIONS

B.1 and B.2 (continued)

1 hour. The alternate hydrogen control capabilities are provided by the Containment Spray System and the Containment Emergency Fan Coolers. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The initial verification may be performed as an administrative check, by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two dome air circulator trains inoperable for up to 7 days. Seven days is a reasonable time to allow two dome air circulator trains to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen.

C.1

If an inoperable dome air circulator train 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. 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Verifying that each dome air circulator fan flow rate is $\geq$ 37,000 cfm ensures that each train is capable of maintaining localized hydrogen concentrations below the flammability limit. The 24 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

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1 (continued)

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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.8.2

This SR ensures that the dome air circulator responds properly to a CCAS. The 24 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.7, March, 1971.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through separate and independent suction lines from the condensate storage tank (CST) (LCO 3.7.6, "Condensate Storage Tank (CST)") and pump to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping inside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1, "Main Steam Safety Valves (MSSVs)") or atmospheric dump valves (ADVs) (LCO 3.7.4, "Atmospheric Dump Valves (ADVs)"). If the main condenser is available, steam may be released via the steam bypass valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. Each motor driven pump provides 100% of AFW flow capacity; the turbine driven pump provides 100% of the required capacity to the steam generators as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system.

Each motor driven AFW pump is powered from an independent Class 1E power supply, and feeds one steam generator, although each pump has the capability to be realigned by local operations to feed the other steam generator.

One pump at full flow is sufficient to remove decay heat and cool the unit to Shutdown Cooling (SDC) System entry conditions.

The steam turbine driven AFW pump receives steam from either main steam header upstream of the main steam isolation valve

(continued)

BASES (continued)

BACKGROUND (continued)

(MSIV). Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump. The turbine driven AFW pump supplies a common header capable of feeding both steam generators, with DC powered control valves actuated to the appropriate steam generator by the Emergency Feedwater Actuation System (EFAS).

The AFW System supplies feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to SDC entry conditions, and steam is released through the ADVs.

The AFW System actuates automatically on low steam generator level by the EFAS as described in LCO 3.3.5, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation." The EFAS logic is designed to feed either or both steam generators with low levels, but will isolate the AFW System from a steam generator having a significantly lower steam pressure than the other steam generator. The EFAS automatically actuates the AFW turbine driven pump and associated DC operated valves and controls when required, to ensure an adequate feedwater supply to the steam generators. DC operated valves are provided for each AFW line to control the AFW flow to each steam generator.

At least three independent steam generator auxiliary feedwater pumps and associated flow paths shall be OPERABLE with:

a. Two motor-driven auxiliary feedwater pumps, each capable of being powered from separate emergency busses,

b. One steam turbine-driven auxiliary feedwater pump capable of being powered from an OPERABLE steam supply system, and

c. Manual valves in the correct position and automatic valves each capable of being opened and closed, with the following exceptions:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

steam turbine driven AFW pump. In such a case, the EFAS logic might not detect the affected steam generator if the backflow check valve to the affected MFW header worked steam generator by the redundant AFW pump.

The AFW System satisfies Criterion 3 of the NRC Policy Statement.

LCO

This LCO requires that three AFW trains be OPERABLE to ensure that the AFW System will perform the 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 two diverse trains, ensure availability of residual heat removal capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two pumps from independent emergency buses. The third AFW pump is powered by a diverse means, a steam driven turbine supplied with steam from a source not isolated by the closure of the MSIVs.

The AFW System is considered to be OPERABLE when the components and flow paths required to provide AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to a separate steam generator. The turbine driven AFW pump shall be OPERABLE with redundant steam supplies from each of the two main steam lines upstream of the MSIVs and capable of supplying AFW flow to either of the two steam generators. The piping, valves, instrumentation, and controls in the required flow paths shall also be OPERABLE.

The LCO is modified by a Note indicating that only one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. This is because of reduced heat removal requirements, the short period of time in MODE 4 during which AFW is required, and the insufficient steam supply available in MODE 4 to power the turbine driven AFW pump.

The LCO Note 2 indicating that the steam driven AFW pump is OPERABLE when running and controlled manually to support plant start-ups, plant shut-downs, and AFW pump and valve testing is necessary because: If a Main Steam Line Break

(continued)

BASES

LCO (continued)

(MSLB) occurs, causing MSIS initiation followed by ESFAS initiation, while the turbine driven AFW pump is operating, the steam driven AFW pump turbine can trip on overspeed. However, the best estimate is that by operating the steam driven AFW Pump in manual, the cumulative core damage frequency CDF decreases by approximately 2E-10/yr. The value of 2E-10/yr is based on the assumption that the steam driven AFW pump is operated in the manual mode approximately 500 minutes per year. This decrease in CDF is a result of the steam driven AFW Pump being available for all other required uses while operating in manual.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE and to function in the event that the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace 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 generator.

In MODES 5 and 6, the steam generators are not normally used for decay heat removal, and the AFW System is not required.

ACTIONS

A.1

If one of the two steam supplies to the turbine driven AFW pumps is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event requiring the inoperable steam supply to the turbine driven AFW pump.

(continued)

BASES (continued)

ACTIONS

A.1 (continued)

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

B.1

With one of the required AFW trains (pump or flow path) inoperable, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the AFW System, the time needed for repairs, and the low probability of a DBA event occurring during this period. Two AFW pumps and flow paths remain to supply feedwater to the steam generators.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combinations of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1

With two AFW trains with two motor driven pumps inoperable in MODES 1, 2, or 3, action must be taken to restore OPERABLE status within 48 hours. This Condition assumes that two steam supplies to AFW steam driven pump are

(continued)

BASES (continued)

ACTIONS

C.1 (continued)

available. The 48 hour Completion Time is reasonable, based on the remaining capability to feed either steam generator by the AFW system, the time needed for repairs, and the low probability of a DBA event occurring during this period.

The steam driven AFW pump and relevant flow path remain to supply feedwater to the steam generators. The Completion Time of 48 hours to restore one AFW motor driven pump to OPERABLE status is less than Completion Time of Condition B to restore one AFW pump to OPERABLE status. Condition C is more restrictive than Condition B.

D.1

With two AFW trains with one motor driven pump and one steam driven pump inoperable in MODES 1, 2, or 3, action must be taken to restore one AFW train to OPERABLE status within 24 hours. This Condition assumes that at least one steam supply to AFW steam driven pump is not available. The 24 hour Completion Time is reasonable, based on the redundant capabilities afforded by the AFW system, the time needed for repairs, and the low probability of a DBA event occurring during this period. The Completion Time of 24 hours to restore one AFW pump to OPERABLE status is less than Completion Time of Condition B or C to restore one AFW pump to OPERABLE status. This conservatism is because the remaining operable motor-driven AFW pump is only capable of feeding one of the steam generators.

E.1 and E.2

When Required Action A.1, B.1, C.1 or D.1 cannot be completed within the required Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve 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.

(continued)

ACTIONS

E.1 and E.2 (continued)

In MODE 4, with two AFW trains inoperable in MODES 1, 2, and 3, operation is allowed to continue because only one motor driven AFW pump is required in accordance with the Note that modifies the LCO. Although it is not required, the unit may continue to cool down and start the SDC.

F.1

Required Action F.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status.

With all three AFW trains inoperable in MODES 1, 2, and 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety grade equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status. LCO 3.0.3 is not applicable, as it could force the unit into a less safe condition.

G.1 and G.2

Required Action G.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status.

With one AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status or to immediately verify, by administrative means, the OPERABILITY of two loops of decay heat removal in accordance with LCO 3.4.6 LCO 3.0.3 is not applicable, as it could force the unit into a less safe condition.

In MODE 4, either the reactor coolant pumps or the SDC loops can be used to provide forced circulation as discussed in LCO 3.4.6, "RCS Loops - MODE 4."

(continued)

BASES (continued)

ACTIONS (continued)

H.1

CONDITION H specifies the requirements for any automatic valve in any AFW flow path upon receipt of a Main Steam Isolation Signal (MSIS). ACTION H.1 requires the automatic valve or its block valve be closed when this automatic valve is incapable of closing upon receipt of a MSIS. REQUIRED ACTION H.2 requires entering appropriate ACTIONS if there is a loss of the flow path(s). These ACTIONS specify AFW system OPERABILITY in the different MODES of operation and in the different AFW system configurations.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW water and steam supply flow paths provides assurance that the proper flow paths exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulations; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

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

SR 3.7.5.2

This SR verifies that the AFW pumps develop sufficient discharge pressure to deliver the required flow at the full open pressure of the MSSVs. Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow. Periodically comparing the reference differential pressure developed at this reduced flow detects trends that might be indicative of incipient failures. Performance of inservice testing, discussed in NUREG 1366 (Ref. 2), on a STAGGERED TEST BASIS satisfies this requirement.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.2 (continued)

LCO 3.7.5 permits plant operation in MODE 4 with one motor driven AFW pump and/or the turbine driven AFW pump inoperable. During plant operation in MODE 4, the turbine driven AFW pump does not have to be surveilled because steam generator pressure is less than 800 psig (NOTE for SR 3.7.5.2). During plant operation in MODE 4 with one motor driven AFW pump inoperable, SR 3.7.5.2 does not have to be performed on the inoperable motor driven pump (SR 3.0.1), and *n* remains at 3, where *n* is the total number of designated components in the definition of STAGGERED TEST BASIS. Therefore, performance of SR 3.7.5.2 on the OPERABLE motor driven AFW pump is only required every 3 Surveillance Frequency intervals. Discussions with the NRC Technical Specifications Branch on this clarification are documented in Action Request 980601488-1.

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

SR 3.7.5.3

This SR ensures that AFW can be delivered to the appropriate steam generator, in the event of any accident or transient that generates an EFAS signal, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. Although testing of some of the components of this circuit may be accomplished during normal operations, the 24 month Frequency is based on the need to complete this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions have been established. This deferral is required because there is an insufficient steam pressure to perform the test.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4

This SR ensures that the AFW pumps will start in the event of any accident or transient that generates an EFAS signal by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal. Although testing of some of the components of this circuit may be accomplished during normal operations, the 24 month Frequency is based on the need to complete this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is acceptable, based on the design reliability and operating experience of the equipment.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions have been established. This deferral is required because there is an insufficient steam pressure to perform the test.

SR 3.7.5.5

This SR ensures that the AFW System is properly aligned by verifying the flow path to each steam generator prior to entering MODE 2 operation, after 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 judgment,and other administrative controls to ensure that flow paths remain OPERABLE. To further ensure AFW System OPERABILITY, the OPERABILITY of the normal flow paths from the CST through the AFW pump to the Steam Generators is verified following extended outages. This SR ensures that the normal paths from the CST to the Steam Generators are OPERABLE by raising Steam Generator level by 2% using AFW flow from the CST.

REFERENCES

1. UFSAR, Section 10.4.9.

2. NUREG 1366, "Improvements to Technical Specifications Surveillance Requirements," Section 9.1

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B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST T-121 and T-120)

BASES

BACKGROUND

The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5, "Auxiliary Feedwater (AFW) System"). The steam produced is released to the atmosphere by the main steam safety valves (MSSVs) or the atmospheric dump valves. The AFW pumps operate with a continuous recirculation to the CST.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam bypass valves. The condensed steam is returned to the CST. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena.

CST T-121 is the suction source for the three AFW pumps. It is designed to Seismic Category I requirements and enclosed in a Seismic Category I vault that provides protection against earthquakes and other natural phenomena. CST T-120 is not Seismic Category I, but is enclosed in a Seismic Category I structure designed to retain water following an earthquake and to provide limited protection against other natural phenomena. CST T-121 can be isolated by Seismic Category I isolation valves. The minimum required volume specified by LCO 3.7.6 ensures that, when S2-1414-MU-092 is isolated within 30 minutes and 2-HV-5715 is isolated within 90 minutes following an Operating Basis Earthquake, sufficient inventory remains in T-120 to meet the requirements described in the Applicable Safety Analysis. Seismic Category I makeup to CST T-121 is provided by gravity feed through cross-ties from T-120 and the T-120 enclosure. Following a tornado event, sufficient inventory remains in T-120 such that water from the T-120 enclosure (which may contain debris) would not be needed.

Backup water supplies are available via non-Seismic Category I makeup to CST T-121 and T-120. Normal makeup is provided by gravity feed from the High Flow Makeup Demineralizer (HFMUD) tanks. Makeup may also be provided by the Units 2 and 3 Fire Water Pumps from the Units 2 and 3 Fire/Service Water Tanks or by the Condensate Transfer System between

(continued)

BASES (continued)

BACKGROUND (continued)

Units 2 and 3. However, the water volume required in the other unit's CST by the other unit's Technical Specifications is not available as a backup supply.

A description of the CST is found in the UFSAR, Section 9.2.6 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides cooling water to remove decay heat and to cool down the unit following all events in the accident analysis (except Large Break LOCA), discussed in the UFSAR, Chapters 3, 6 and 15 (Refs. 2, 3, and 4 respectively). For anticipated operational occurrences and accidents which do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 30 minutes at MODE 3, steaming through the MSSVs followed by a cooldown using the ADVs to shutdown cooling (SDC) entry SAFETY ANALYSES conditions at the design cooldown rate.

The limiting event for the condensate volume is the Reactor Systems Branch Technical Position 5-1 (RSB 5-1) safe shutdown scenario. For the RSB 5-1 scenario, safe shutdown must be demonstrated using only safety grade systems, assuming a coincident loss of onsite or offsite power, and a concurrent single failure. For sizing of the condensate volume, 24 hours of steaming are assumed, including 4 hours at hot standby prior to initiating cooldown. Additionally, calculated losses over a 30-minute period prior to isolation of S2-1414-MU-092 and a 90-minute period prior to isolation of 2-HV-5715, are considered in the sizing of the volume. An additional allotment of 32,616 gallons is included for future allocations to provide for any "as yet" unidentified uses or losses. The limiting single failures for the RSB 5-1 scenario are:

a. Failure of an Atmospheric Dump Valve on one steam generator. This limits the steaming rate and prolongs the cooldown to Shutdown Cooling entry conditions. This is the most limiting failure for condensate sizing.

b. Failure of one Diesel Generator. This limits the available cooldown rate from Shutdown Cooling entry to cold shutdown. This is the most limiting failure for time to cold shutdown.

The CST satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

ACTIONS

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance onsteam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. The required volume of cooling water in CST T-121 is 144,000 gallons. The required volume of cooling water in CST T-120 is 360,000 gallons above the tank's zero datum. That corresponds to 52%. The 12 hour Frequency is based on operating experience, and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. The 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal CST level deviations.

REFERENCES

1. UFSAR, Section 9.2.6.
2. UFSAR, Chapter 3
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 15.

LCO (continued)

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

APPLICABILITY

In MODES 1, 2, 3, and 4, the CREACUS must be OPERABLE to limit operator exposure during and following a DBA.

In MODES 5 and 6, the CREACUS is required to cope with the release from a rupture of a waste gas tank.

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

ACTIONS

ACTION statements are modified by two NOTES. NOTE 1 says: "The provisions of LCO 3.0.4 are not applicable when entering MODES 5, 6, or defueled configuration."

Specification 3.0.4 establishes that entry into an operational mode or other specified condition shall not be made unless the conditions of the LCO are met. Applicability statement "During movement of irradiated fuel assemblies" ensures the OPERABILITY of both CREACUS trains prior to the start of movement of irradiated fuel assemblies.

NOTE 2 says: "Each Unit shall enter applicable ACTIONS separately." CREACUS is a shared system between Unit 2 and Unit 3. LCO doesn't address the operational situation when the Units are in different operational MODES. Without this NOTE it may not be clear what ACTIONS should be taken.

A.1

With one CREACUS train inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREACUS subsystem is adequate to perform control room radiation protection function.

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.18 Spent Fuel Assembly Storage

BASES

BACKGROUND	The spent fuel storage facility is designed to store either new (nonirradiated) nuclear fuel assemblies, or burned (irradiated) fuel assemblies in a vertical configuration underwater. The storage pool is sized to store 1542 fuel assemblies. Two types/sizes of spent fuel storage racks are used (Region I and Region II). The two Region I racks each contain 156 storage locations each spaced 10.40 inches on center in a 12x13 array. Four Region II storage racks each contain 210 storage locations in a 14x15 array. The remaining two Region II racks each contain 195 locations in a 13x15 array. All locations are spaced 8.85 inches on center. This spacing and "flux trap" construction, whereby the fuel assemblies are inserted into neutron absorbing stainless steel cans, is sufficient to maintain a k_{eff} of $\leq$ 0.95 for spent fuel of original enrichment of up to 4.1%. However, as higher initial enrichment fuel assemblies are stored in the spent fuel pool, they must be stored in a checkerboard pattern taking into account fuel burnup to maintain a k_{eff} of 0.95 or less.
APPLICABLE SAFETY ANALYSES	The spent fuel storage facility is designed for noncriticality by use of adequate spacing, and "flux trap" construction whereby the fuel assemblies are inserted into neutron absorbing stainless steel cans. The spent fuel assembly storage satisfies Criterion 2 of the NRC Policy Statement.
LCO	The restrictions on the placement of fuel assemblies within the spent fuel pool, according to Figure 3.7.18-1 and Figure 3.7.18-2, in the accompanying LCO, ensures that the k_{eff} of the spent fuel pool will always remain < 0.95 assuming the pool to be flooded with unborated water. The restrictions are consistent with the criticality safety analysis performed for the spent fuel pool according to

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.19 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives, and thus is indication of current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 0.5 gpm per steam generator (1 gpm total) tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives (i.e., < 20 hours). I-131, with a half life of 8.04 days, concentrates faster than it decays, but does not reach equilibrium because of blowdown and other losses.

With the specified activity level, the resultant 2 hour thyroid dose to a person at the exclusion area boundary (EAB) would be about 4.5 rem should a steam generator atmospheric dump valve inadvertently open.

Therefore, operating a unit at the allowable limits could result in a 2 hour EAB exposure within the 10 CFR 100 (Ref. 1) limits (300 rem for thyroid dose to a person).

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B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

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

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

In Modes 1 through 4, the normal preferred power source (Offsite circuit #1) for each unit is Reserve Auxiliary Transformers XR1 and XR2 for the specific unit. XR1 feeds one 4.16 kV ESF bus (Train A) A04 and XR2 feeds the other 4.16 kV ESF bus (Train B) A06 of the onsite Class 1E AC distribution system for each unit. The alternate preferred power source (Offsite circuit #2) is the other unit's Reserve Auxiliary Transformers XR1 and XR2, or the other unit's Unit Auxiliary Transformer XU1 through the train oriented 4.16 kV ESF bus cross-ties between the two units. The 4.16 kV ESF bus alignment in the other unit determines which transformer(s) serves as the alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Reserve Auxiliary Transformer (XR1 or XR2), then that transformer is the required alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Unit Auxiliary Transformer (XU1), then that transformer is the required alternate preferred power source.

In Modes 5 and 6, when the main generator is not operating, each Class 1E Switchgear can be connected to a third preferred power source via the Unit Auxiliary Transformers by manually removing the links in the isolated phase bus between the Main Generator and the Main

(continued)

BACKGROUND (continued)

transformer of the non-operating (Modes 5 and 6) unit and closing the 4.16 kV circuit breaker to the Unit Auxiliary transformer of the same unit. In this alignment, the Unit Auxiliary Transformer (XU1) serves as the required normal preferred power source of the unit and the alternate preferred power source for the ESF bus(es) in the other unit.

An offsite circuit includes all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus or buses.

During a Safety Injection Actuation Signal (SIAS), certain required ESF loads are connected to the ESF buses in a predetermined sequence. Within 77 seconds after the SIAS, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are placed in service.

The standby (onsite) power source for each 4.16 kV ESF bus is a dedicated DG. DGs G002 and G003 are dedicated to ESF buses A04 and A06, respectively. A DG starts automatically on a SIAS (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage signal. After the DG has started, it will automatically connect to its respective bus after the offsite power supply breaker is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with a SIAS signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on a~~n~~ SIAS alone. Following the trip of offsite power, an undervoltage signal strips selected loads from the ESF bus. When the DG is tied to the ESF bus, the permanently connected loads are energized. If one or more ESF actuation signals are present, ESF loads are then sequentially connected to their respective ESF bus by the programmed time interval load sequence. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

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

(continued)

BACKGROUND (continued)

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 4700 kW with 10% overload permissible for up to 2 hours in any 24 hour period. However, for standby class of service like the San Onofre DGs the manufacturer allows specific overload values up to 116.1% of continuous duty rating based on the total hours the DG is operated per year. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

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

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

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

b. A worst case single failure.

The AC sources satisfy Criterion 3 of NRC Policy Statement.

LCO

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

(continued)

LCO (continued)

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. Required offsite circuits are those circuits that are credited and required to be Operable per LCO 3.8.1.

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

In Modes 1 through 4, the normal preferred power source (Offsite circuit #1) for each unit is Reserve Auxiliary Transformers XR1 and XR2 for the specific unit. XR1 feeds one 4.16 kV ESF bus (Train A) A04 and XR2 feeds the other 4.16 kV ESF bus (Train B) A06 of the onsite Class 1E AC distribution system for each unit. The alternate preferred power source (Offsite circuit #2) is the other unit's Reserve Auxiliary Transformers XR1 and XR2, or the other unit's Unit Auxiliary Transformer XU1 through the train oriented 4.16 kV ESF bus cross-ties between the two units. The 4.16 kV ESF bus alignment in the other unit determines which transformer(s) serves as the alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Reserve Auxiliary Transformer (XR1 or XR2), then that transformer is the required alternate preferred power source. If the 4.16 kV ESF bus in the other unit is aligned to the Unit Auxiliary Transformer (XU1), then that transformer is the required alternate preferred power source.

In Modes 5 and 6, when the main generator is not operating, each Class 1E Switchgear can be connected to a third preferred power source via the Unit Auxiliary Transformers by manually removing the links in the isolated phase bus between the Main Generator and the Main transformer of the non-operating (Modes 5 and 6) unit and closing the 4.16 kV circuit breaker to the Unit Auxiliary transformer of the same unit. In this alignment, the Unit Auxiliary Transformer (XU1) serves as the required normal preferred power source of the unit and the alternate preferred power source for the ESF bus(es) in the other unit.

Each DG must be capable of starting, accelerating to within specified frequency and voltage limits, connecting to its respective ESF bus on detection of bus undervoltage, and resetting the 4.16 kV bus undervoltage relay logic, in less than or equal to 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading

(continued)

LCO (continued)

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, DG in standby with the engine at ambient conditions, and DG operating in a parallel test mode. A DG is considered already operating if the DG voltage is $\geq$ 4297 and $\leq$ 4576 volts and the frequency is $\geq$ 59.7 and $\leq$ 61.2 Hz.

Proper sequencing of loads, including tripping of nonessential loads on a SIAS, is a required function for DG OPERABILITY.

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

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with transfer capability to the other circuit, and not violate separation criteria.

APPLICABILITY

The AC sources and associated automatic load sequence timers are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

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

ACTIONS

A.1

To ensure a highly reliable power source remains with the one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on

(continued)

ACTIONS

A.1 (continued)

a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. 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.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 day Completion Time means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

ACTIONS

A.2 (continued)

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

As required by Section 5.5.2.14, a Configuration Risk Management Program is implemented in the event of Condition A.

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as turbine driven auxiliary feedwater pumps, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

(continued)

ACTIONS

B.2 (continued)

Reference 18 contains information implying that for a component or system to be considered a "required feature," it must meet **ALL** the following criteria:

- perform a safety function;
- require electrical power from a class 1E power source to perform its safety function (see Note 1);
- be credited to perform the safety function in loss of offsite power events;
- be redundant to a system or component in the opposite train that performs the same safety function;
- fail in a position on loss of electrical power that does not fulfill the safety function.

Note 1: Systems or components that are powered from a Class 1E battery or inverter are "required features" ONLY if credited to perform their safety function at a time in the event that is longer than the UFSAR assumed life of the associated class 1E battery, AND all other above criteria are met (for example, redundant post accident monitoring instrumentation and atmospheric dump valves).

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:

(continued)

ACTIONS

B.2 (continued)

a. An inoperable DG exists; and

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

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

Discovering one required DG inoperable coincident with one or more 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 DGs. 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 other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

(continued)

ACTIONS

B.3.1 and B.3.2 (continued)

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

An augmented analysis using the methodology set forth in Reference 16 provides a series of deterministic and probabilistic justifications and supports continued operations in Condition B for a period that should not exceed 14 days.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "<u>AND</u>" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

(continued)

ACTIONS

B.4 (continued)

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

As required by Section 5.5.2.14, a Configuration Risk Management Program is implemented in the event of Condition B.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from the 24 hours allowed by Regulatory Guide 1.93 (Ref. 6) for two inoperable required offsite circuits. The 24 hour allowance is based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train turbine driven auxiliary pumps, are not included in the list.

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

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

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

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

(continued)

ACTIONS

C.1 and C.2 (continued)

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.

(continued)

ACTIONS (continued)

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System (LCO 3.8.9) ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

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

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

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a 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

(continued)

ACTIONS

E.1 (continued)

time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

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

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 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 unit systems.

G.1

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

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, 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).

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SURVEILLANCE REQUIREMENTS (continued)

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 4297 V is above the maximum reset voltage of the 4.16 kV bus undervoltage relays (Ref. SR 3.3.7). Achieving a voltage at or above 4297 V ensures that the LOVS/SDVS/DGVSS relay logic will reset allowing sequencing of the ESF loads on to the ESF bus if one or more ESF actuation signals is present. This minimum voltage limit, which is consistent with ANSI C84.1-1982 (Ref. 11), is above the allowed voltage drop to the terminals of 4160 V motors whose minimum steady state operating voltage is 3744 V (90% of 4160 V). This minimum voltage requirement also ensures that adequate voltage is provided to motors and other equipment down through the 120 V level. The specified maximum steady state output voltage of 4576 V ensures that, for a lightly loaded distribution system, the voltage at the terminals of 4160 V motors is no more than the maximum allowable steady state operating voltage (110% of 4160V). The specified minimum and maximum frequencies of the DG are 59.7 Hz and 61.2 Hz, respectively. The upper frequency limit is equal to + 2% of the 60 Hz nominal frequency and is derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3). The lower frequency limit is equal to - 0.5% of the 60 Hz nominal frequency and is based on maintaining acceptable high pressure safety injection system performance as assumed in the accident analyses.

During a DG surveillance test, steady state DG voltage of 4297 to 4576 volts and steady state frequency of 59.7 to 61.2 Hz shall be verified. For the lower voltage and frequency limits, the Total Loop Uncertainty (TLU) of the measurement device (Reference Calculation E4C-098) shall be considered.

<u>SR 3.8.1.1</u>

This SR assures 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 availability of independent 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.

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SURVEILLANCE REQUIREMENTS (continued)

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, DG starts may be preceded by an engine prelube period. SR 3.8.1.2 is modified by Notes 2 and 3 to indicate that all DG starts for SR 3.8.1.2 may be preceded by an engine prelube period and followed by a warmup period prior to loading. The DG manufacturer recommends a modified (slow) start (when possible) in which the starting speed of the DG is limited, warmup is limited to this lower speed, and the DG is gradually accelerated to rated speed prior to loading. SR 3.8.1.7 is modified by Note 1 to indicate that all DG starts for SR 3.8.1.7 may be preceded by an engine prelube period.

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 the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.7 requires that the DG starts from standby conditions and achieves required voltage and frequency within 9.4 seconds without DG breaker closure. The 9.4 second start requirement ensures that the DG meets the design basis LOCA analysis assumptions (Ref. 5), that the DG starts, accelerates to within the specified frequency and voltage limits, connects to the 4.16kV ESF bus, and resets the ESF bus undervoltage relay logic within 10 seconds of a SIAS.

The 9.4 second start requirement is not applicable to SR 3.8.1.2 when a modified (slow) start procedure described above is used. Since SR 3.8.1.7 requires a 9.4 second start, it is more restrictive than SR 3.8.1.2 and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and is evaluated to identify degradation of governor and voltage regulator performance.

SR 3.8.1.7 is modified by Note 2 which acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule," in the accompanying LCO) and the 184 day Frequency for SR 3.8.1.7 are consistent with Regulatory Guide 1.9 (Ref. 3). 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 listed in Reference 2. This capability is verified by performing a load test between 90 to 100% of rated load, for an interval of not less than 60 minutes, consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The lower load limit of 4450 kW is 94.7% of the DG continuous rating (4700 kW). The 94.7% limit is based on design basis loading and includes instrument uncertainty plus margin. Instrument uncertainty is not applied to the upper load limit. 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.

Although no power factor requirements are established by this SR, the surveillance is performed with DG kVAR output that offsite power system conditions permit during testing without exceeding equipment ratings (i.e., without creating an overvoltage condition on the ESF buses, over excitation condition on the ESF buses, over excitation condition in the generator, or overloading the DG main feeder). The kVAR loading requirement during this test is met, and the equipment ratings are not exceeded, when the DG kVAR output is increased such that:

a. kVAR is ≥ 3000 and ≤ 3200 or
b. the excitation current is ≥ 3.8 A and ≤ 4.0 A or
c. the ESF bus voltage is ≥ 4530 V and ≤ 4550 V or
d. DG feeder current is ≥ 730 A and ≤ 750 A

This method of establishing kVAR loading ensures that, in addition to verifying the load carrying capability (kW) of the diesel engine, the reactive power (kVAR) and voltage

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

regulation capability of the generator is verified to the extent practicable, consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Information Notice 91-13 (Ref. 16).

The normal 31 day Frequency for this Surveillance (Table 3.8.1-1) 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 DG load transients do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates that a successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%. The level is expressed as an equivalent volume in inches. The 30 inch level includes instrument uncertainties and corresponds to the minimum requirement of 355.1 gallons of fuel oil.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit 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 microorganisms 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 microbial survival in the day tanks. This is the most effective means of controlling

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

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 from breakdown of the fuel oil by microorganisms. 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 preventive 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 for each OPERABLE DG at least one 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 the standby power source. This Surveillance provides assurance that at least one 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 the fuel transfer system are OPERABLE.

The design of the fuel transfer system is such that one pump will operate automatically, while the other pump can be started manually. Either pump will maintain an adequate volume of fuel oil in the day tank. In such a case, a 31 day Frequency is appropriate.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Verification of the capability to transfer each 4.16 kV ESF bus power supply from the normal preferred power source (offsite circuit) to each required alternate preferred power source (offsite circuit), via the train-aligned 4.16 kV

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

crosstie between Unit 2 and Unit 3, demonstrates the OPERABILITY of the alternate preferred power distribution network to power the post-accident and shutdown loads. For 2A04 the normal offsite power source is 2XR1, and the alternate offsite power source is 3XR1 or 3XU1. For 2A06 the normal offsite power source is 2XR2, and the alternate offsite power source is 3XR2 or 3XU1. A required alternate offsite power source is the source that is credited as the alternate source of offsite power in LCO 3.8.1. Therefore, the alignment of the ESF buses in Unit 3 determines which alternate offsite circuit is the required circuit at any point in time.

For each 4.16 kV ESF bus (2A04 or 2A06) this surveillance requirement may be satisfied by performing both a manual transfer and an auto-transfer from the normal offsite power source to at least one of the alternate offsite power sources. The tested source may then be credited as the required alternate offsite power source per LCO 3.8.1. This surveillance may be satisfied for the remaining power source by performing a circuit functional test in addition to the transfer test above. This functional test shall be performed such that all components that are required to function for a successful manual or auto-transfer that were not included in the transfer tests above, are tested. This testing may include any series of sequential, overlapping, or total steps so that the entire manual and auto-transfer capability of the source is verified. This is explained in a note to this SR.

The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note which acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single post-accident load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. For this unit, the largest single post-accident load for each DG is the Auxiliary Feedwater pump which has a nameplate rating of 800 HP. As required by IEEE-308 (Ref. 13), the load rejection test is acceptable if the DG frequency does not exceed 66.75 Hz, which is 75% of the difference between synchronous speed (60 Hz) and the overspeed trip setpoint (69 Hz).

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequencing and load rejection. The 4 seconds specified is equal to 80% of the 5 second load sequence interval associated with sequencing of the largest load. Since SONGS specific analyses demonstrate the acceptability of overlapping load groups (i.e., adjacent load groups that start at the same time due to load sequence timer tolerance), the use of 80% of load sequence interval for voltage recovery is consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed by rejecting an inductive load with kW and kVAR greater than or equal to the single largest post-accident load (683 kW, 369 kVAR). These test conditions are consistent with the power factor requirements of Regulatory Guide 1.9 (Ref. 3) and the recommendations of Information Notice 91-13 (Ref. 16).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

This SR is modified by a Note which acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a load equal to 90% to 100% of its continuous rating without overspeed tripping or exceeding the predetermined voltage limits. The lower load limit of 4450 kW is 94.7% of the DG continuous rating (4700 kW). The 94.7% limit is based on design basis loading and includes instrument uncertainty plus margin. Instrument uncertainty is not applied to the upper load limit.

The DG full load rejection may occur because of a system fault, inadvertent breaker tripping or a SIAS received during surveillance testing. This Surveillance ensures proper engine and generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG will not trip upon loss of the load. The voltage transient limit of 5450 V is 125% of rated voltage (4360 V). These acceptance criteria provide 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 (e.g., reconnection to the bus if the trip initiator can be corrected or isolated). These loads and limits are consistent with Regulatory Guide 1.9 (Ref. 3).

The DG is tested under inductive load conditions that are as close to design basis conditions as possible. Testing is performed with DG kVAR output that offsite power system conditions permit during testing without exceeding equipment ratings (i.e., without creating an overvoltage condition on the ESF buses, over excitation condition in the generator, or overloading the DG main feeder). The kVAR loading requirement during this test is met, and the equipment ratings are not exceeded, when the DG kVAR output is increased such that:

a. kVAR is ≥ 3000 and ≤ 3200 or
b. the excitation current is ≥ 3.8 A and ≤ 4.0 A or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

c. the ESF bus voltage is ≥ 4530 V and ≤ 4550 V or
d. DG feeder current is ≥ 730 A and ≤ 750 A

This method of establishing kVAR loading ensures that, in addition to verifying the full load rejection capability (kW) of the diesel engine, the reactive power rejection capability (kVAR) of the generator is verified to the extent practicable, consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Information Notice 91-13 (Ref. 16).

The 24 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note which acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), 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 selected loads and energization of the permanently connected loads from the DG. The permanently connected loads are the Class 1E 480 V Loadcenters and MCCs. It is recognized that certain consequential loads may also start following a loss of offsite power and therefore it is important to demonstrate that the DG operates properly with these loads. The consequential loads are sequenced on the DG following a LOVS with the same time delays as for a LOVS with a SIAS. Therefore, the ability of the DG to operate with the consequential loads is appropriately demonstrated by the existing Surveillance Requirement simulating a loss of offsite power in combination with a SIAS (Surveillance Requirement 3.8.1.19). Since there are no auto-connected shutdown loads, the Regulatory Guide 1.9 (Ref. 3) requirements for sequencing of auto-connected shutdown loads do not apply (Ref. 17). This surveillance further demonstrates the capability of the DG to automatically achieve the required voltage and frequency, to close the DG output breaker and connect to the ESF bus, and to reset the 4.16 kV bus undervoltage relay logic within the specified time.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

The DG auto-start and undervoltage relay logic reset time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The frequency should be restored to within the specified range following energization of the permanently connected loads. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent 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, high pressure injection systems are not capable of being operated at full flow, or shutdown cooling (SDC) 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 shedding, connection, and loading of loads, overlap 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 sequence of load shedding and reenergization of permanently connected loads is verified.

The Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.9 (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. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that after a SIAS, the DG automatically starts and achieves the required voltage and frequency within the specified time and operates for ≥ 5 minutes. The 9.4 second start requirement ensures that the DG meets the design basis LOCA analysis assumption, that the DG starts, accelerates to within the specified frequency and voltage limits, connects to the 4.16 kV ESF bus, and resets the ESF bus undervoltage relay logic within 10 seconds of a SIAS. The 5 minute period provides sufficient time to demonstrate stability.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and is evaluated to identify degradation of governor and voltage regulator performance.

The Frequency of 24 months is consistent with Regulatory Guide 1.9 (Ref. 3), 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

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. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a SIAS in accordance with Regulatory Guide 1.9 (Ref. 3). The critical protective functions (engine overspeed, generator differential current, and low-low lube oil pressure), which trip the DG to avert substantial damage to the DG unit, are not bypassed. 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 to prevent damage to the DG. The DG availability to mitigate the DBA is more critical thanprotecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

Testing to satisfy this surveillance requirement may include any series of sequential, overlapping, or total steps so that the entire noncritical trip bypass function is verified.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, 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 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint. The SR is modified by a Note which acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per refueling outage 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 load equivalent to 105% to 110% of the continuous duty rating and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG. For the 22 hour duration, the lower load limit of 4450 kW is 94.7% of the DG continuous rating (4700 kW). The 94.7% limit is based on design basis loading and includes instrument uncertainty plus margin. Instrument uncertainty is not applied to the 100%, 105% or 110% load limits.

This test is performed with the DG connected to the offsite power supply. In this alignment DG frequency is controlled by the offsite power supply, and the operator has minimal control over DG output voltage. Therefore, specific DG voltage and frequency requirements as recommended by Regulatory Guide 1.9 (Ref. 3) do not apply.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

The DG is tested under inductive load conditions that are as close to design conditions as possible. Testing is performed with DG kVAR output that offsite power system conditions permit during testing without exceeding equipment ratings (i.e., without creating an overvoltage condition on the ESF buses, over excitation condition in the generator, or overloading the DG main feeder). The kVAR loading requirement during this test is met, and the equipment ratings are not exceeded, when the DG kVAR output is increased such that:

a. kVAR is ≥ 3000 and ≤ 3200 or
b. the excitation current is ≥ 3.8 A and ≤ 4.0 A or
c. the ESF bus voltage is ≥ 4530 V and ≤ 4550 V or
d. DG feeder current is ≥ 730 A and ≤ 750 A

This method of establishing kVAR loading ensures that, in addition to verifying the load carrying capability (kW) of the diesel engine, the reactive power (kVAR) and voltage regulation capability of the generator is verified to the extent practicable, consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Information Notice 91-13 (Ref. 16).

The kW load band in the SR 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 24 month Frequency is consistent with the recommendations of Regulatory Guide 1.9, (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by two Notes. Note 1 states that momentary DG load transients do not invalidate this test. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

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 9.4 seconds. The 9.4 second time is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The LOCA analysis assumes that the DG starts, accelerates to within the specified frequency and voltage limits, connects to the 4.16 kV ESF bus, and resets the ESF bus undervoltage relay logic within 10 seconds of a SIAS.

In addition to the SR requirements, the time for the DG to reach steady state operation, unless the modified DG start method is employed, is periodically monitored and is evaluated to identify degradation of governor and voltage regulator performance.

The 24 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

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 DG load transients 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 (Ref. 3), this Surveillance ensures manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready to load operation when offsite power is restored. Ready to load operation is defined as the DG running within the specified frequency and voltage limits, with the DG output breaker open. If this test is performed with a SIAS present, the load transfer occurs when the offsite power breaker is manually closed, and the SIAS causes the DG output breaker to open. If this test is performed without a SIAS present, the load transfer occurs when the offsite power breaker is manually closed, and the DG output breaker is manually opened. By design, the LOVS/SDVS/DGVSS logic will have been previously reset thus allowing the DG to reload if a subsequent loss of offsite power or degraded voltage condition occurs. The LOVS/SDVS/DGVSS signal will strip the bus, reset the load sequence timers, close the DG output breaker, and permit

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.16 (continued)

resequencing of the ESF loads if an ESF actuation signal is present.

The Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.9 (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 which acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

For this Surveillance, the DG is in test mode when it is running, connected to its bus, and in parallel with offsite power. Demonstration of the test mode override ensures that:

1) the DG availability under accident conditions will not be compromised as the result of testing with the DG connected to its bus in parallel with offsite power, and

2) the DG will automatically return to ready to load operation,

if a SIAS is received during operation in the test mode. Ready to load operation is defined as the DG running within the specified frequency and voltage limits, with the DG output breaker open. These provisions are required by IEEE-308 (Ref. 13), paragraph 6.2.6(2) and Regulatory Guide 1.9 (Ref. 3).

The intent in the requirement to automatically energize the emergency loads with offsite power associated with SR 3.8.1.17.b is to show that the emergency loading was not affected by DG operation in the test mode in parallel with offsite power. 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.

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SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

The 24 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (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 which acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.18

Under accident conditions, electrical loads are sequentially connected to a DG bus by the programmed time interval load sequence. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DG due to high motor starting currents. The load sequence start time 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. Table B 3.8.1-1 provides a matrix of loads sequenced by the ESF timing logic. The timer as-left setting requirement and the as-found acceptance criteria are provided in Table B 3.8.1-1.

For the Containment Emergency Cooling Units only, the sequenced time is the actual start time of the Component Cooling Water pumps plus 5 + 2.5/-0.5 seconds. The tolerance is based on a design interval of 5 seconds.

This testing may include any series of sequential, overlapping, or total steps so that all load sequence timers are verified.

(continued)

TABLE B 3.8.1-1: DG LOAD SEQUENCING TIMER ACCEPTANCE CRITERIA

		Start Time (Sec)	Nominal Setting (As Left) Tolerance (Sec)	As-Found Tolerance (Sec)
1.	LPSI Pumps P015, P016	5.00	±0.5	-0.5 +2.5
2.	Dome Air Circulating Fans A071, A072, A073, A074	5.00	±0.5	-0.5 +2.5
3.	Control Room AC Units E418, E419	5.00	±0.5	-0.5 +2.5
4.	Containment Spray Pumps P012, P013	10.00	±0.5	±2.5
5.	Diesel Generator Radiator Fans E546, E547, E549, E550	10.00	±0.5	±2.5
6.	Component Cooling Water Pumps P024, P025, P026	15.00	±0.5	±2.5
6A.	Containment Emergency Cooling Units E399, E400, E401, E402	CCW Pump Breaker Closure +5 secs	±0.5*	-0.5* +2.5*
7.	Diesel Generator Building Emergency Fans A274, A275, A276, A277	15.00	±0.5	±2.5
8.	Salt Water Cooling Pumps P112, P307, P113, P114	20.00	±0.5	±2.5
9.	Auxiliary Feed Water Pumps P141, P504	30.00	±0.5	±3.0
10.	Emergency Chillers E335, E336	35.00	±0.5	±3.5

*Emergency Cooling Unit time delay as measured from closure of the CCW pump breaker position switch 152-1.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18 (continued)

As required by Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2), each DG is required to demonstrate proper operation for the DBA loading sequence to ensure that voltage and frequency are maintained within the required limits. This surveillance is performed in SR 3.8.1.19. The sequence relays tested under SR 3.8.1.18 are required to support proper DG loading sequence.

The Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(2); 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 which acknowledges that credit may be taken for unplanned events that satisfy this SR.

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 an actual or simulated loss of offsite power signal (LOVS/DGVSS/SDVS) in conjunction with actual or simulated ESF actuation signals (SIAS, CCAS, CSAS, EFAS-1, and EFAS-2). Multiple ESF actuation signals are initiated to simulate worst case DG load sequencing conditions.

In lieu of actual demonstration of shedding, 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 load shedding, connection, and loading sequence is verified.

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 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. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. 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), paragraph 2.b, Regulatory Guide 1.137 (Ref. 10), paragraph C.2.f, and Regulatory Guide 1.9 (Ref. 3).

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

Diesel Generator Test Schedule

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability above 0.95 per demand.

According to Regulatory Guide 1.9, Revision 3 (Ref. 3), each DG unit should be tested at least once every 31 days. According to Draft Regulatory Guide DG-1021 (Ref. 14) and 10 CFR 50.63(a)(3)(ii) (Ref. 15), whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability.

When considered in the light of a long history of tests, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency will allow for a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive, failure free tests have been performed.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20 (continued)

The Frequency for accelerated testing is 7 days, but no less than 24 hours. Therefore, the interval between tests should be no less than 24 hours, and no more than 7 days. A successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts. A test interval in excess of 7 days constitutes a failure to meet the Srs.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0.
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1.
10. Regulatory Guide 1.137, Rev. 1.
11. ANSI C84.1-1982.
12. ASME, Boiler and Pressure Vessel Code, Section XI.
13. IEEE Standard 308-1978.
14. Draft Regulatory Guide DG-1021, April 1992.
15. 10 CFR 50.63(a)(3)(ii) as published in Federal Register Vol. 57, No. 77 page 14517, April 21, 1992.
16. Information Notice 91-13, "INADEQUATE TESTING OF EMERGENCY DIESEL GENERATORS (EGDs)," 09/16/91.
17. Letter from SCE to the NRC dated May 5, 1995, subject Docket Nos. 50-361 and 50-362, Diesel Generator Loading San Onofre Nuclear Generating Station Units 2 and 3.
18. Letter from the NRC to SCE dated May 12, 1999, subject Technical Specification Interpretation (TAC Nos. MA0232 and MA0233).

BASES (continued)

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4

With the offsite circuit not available to the required train (Condition A), the option exists to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable (Condition B), the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

Notwithstanding performance of the conservative Required Actions, the unit is still without sufficient AC power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required AC power sources and continue until the LCO requirements are restored.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

(continued)

BASES (continued)

ACTIONS

A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4 (continued)

Pursuant to LCO 3.0.6, the Distribution System's (LCO 3.8.10) ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to one ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.17 is not required to be met because the required OPERABLE DG is not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with DG(s) that are not required to be OPERABLE.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable. With limited AC Sources available, a single event could unnecessarily compromise both the required circuit and the DG. The SRs listed in the Note are not required to be performed for the OPERABLE AC sources during Modes 5 and 6, and during movement of irradiated fuel assemblies. However, these AC sources are presumed to be able to meet these surveillances. If it is discovered (through analysis or unplanned events, for example) that the required AC sources could not meet these surveillances, then the equipment must be considered inoperable. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

1. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources – Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC vital bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of four independent and redundant safety related Class 1E DC electrical power subsystems (Train A, Train B, Train C and Train D). Each subsystem consists of one 125 VDC battery, a battery charger for the battery, and all the associated control equipment and interconnecting cabling.

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

Train A and Train B 125 VDC electrical power subsystems provide control power for the 4.16 KV switchgear and 480 V load center AC load groups A and B, Diesel generator A and B control systems, and Train A and B control systems, respectively. Train A and Train B DC subsystems also provide DC power to the Train A and Train B inverters, as well as to Train A and Train B DC valve actuators, respectively.

Train C and Train D 125 VDC electrical power subsystems provide power for NSSS control power and DC power to Train C and Train D inverters, respectively. Train C DC subsystem also provides DC power to the Auxiliary Feedwater Pump inlet valve HV-4716 and the AFWP electric governor.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

positive reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6)). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events.

Notwithstanding performance of the above conservative Required Actions, the unit is still without sufficient DC power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required DC power sources and continue until the LCO requirements are restored.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

B.1

Condition B represents one train with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. Since eventual failure of the battery to maintain the required

(continued)

BASES (continued)

ACTIONS

B.1 (continued)

battery cell parameters is highly probable, it is imperative that the operator's attention focus on minimizing the potential for complete loss of DC power to the affected train. The additional time provided by the Completion Time is consistent with the battery's capability to maintain its short term capability to respond to a design basis event.

C.1

If the battery cell parameters cannot be maintained within Category A limits, the short term capability of the battery is also degraded and the battery must be declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 states that Surveillances required by SR 3.8.4.1 through SR 3.8.4.8 are applicable in these MODES. See the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note which indicates that SR 3.8.4.6 (battery charger capacity), SR 3.8.4.7 (battery service test), and SR 3.8.4.8 (battery performance test), if expired, are not required to be performed for the OPERABLE DC subsystems in Modes 5 and 6, and during movement of irradiated fuel assemblies. However, the DC subsystems are presumed to be able to meet these surveillances. If it is discovered (through analysis or unplanned events, for example) that the charger and/or battery could not meet these surveillances, then the equipment must be considered inoperable.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.

BASES (continued)

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery. The footnotes to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity.

Restoring Operability of a Recharged Battery

A battery may be restored to OPERABLE condition if the pilot cells meet Table 3.8.6-1 Category C parameters. All connected cells must be demonstrated to meet Table 3.8.6-1 Category C parameters within 24 hours of restoring the battery to OPERABLE. All connected cells must be demonstrated to meet Table 3.8.6-1 Category A and B parameters within 31 days of restoring the battery to OPERABLE.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. IEEE-450-1980.

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, the unit is still without sufficient AC vital power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required AC vital power source and continue until the LCO requirements are restored.

(continued)

BASES (continued)

ACTIONS	A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued) The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.
SURVEILLANCE REQUIREMENTS	SR 3.8.8.1 This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.
REFERENCES	1. UFSAR, Chapter 6. 2. UFSAR, Chapter 15.

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystems LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (Mode 5) or boron concentration (Mode 6)). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 what would be required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required shutdown cooling (SDC) subsystem may be inoperable. In this case, these Required Actions of Condition A do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the SDC ACTIONS would not be entered.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5 (continued)

Therefore, the Required Actions of Condition A direct declaring SDC inoperable, which results in taking the appropriate SDC actions.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution system is functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

BASES (continued)

LCO (continued)	COLR ensures a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.
APPLICABILITY	This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM) – $T_{avg} > 200°F$," and LCO 3.1.2, "SHUTDOWN MARGIN – $T_{avg} \leq 200°F$," ensure that an adequate amount of negative reactivity is available to shut down the reactor and to maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, or the refueling canal is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately. Operations that individually add limited positive reactivity (e.g., temperature fluctuations from inventory addition or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, there is no unique design basis event that must be satisfied. The only requirement is to restore the boron concentration to its required value as

(continued)

BASES (continued)

APPLICABILITY

In MODE 6, the SRMs must be OPERABLE to determine changes in core reactivity. There is no other direct means available to check core reactivity levels.

In MODES 3, 4, and 5, the installed source range detectors and circuitry are required to be OPERABLE by LCO 3.3.13, "Source Range Monitors."

ACTIONS

A.1 and A.2

With only one SRM OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and introduction of coolant into the RCS 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 what would be 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.

Temperature fluctuations associated with maintaining the plant status are permissible provided they remain within limits established for the plant conditions.

B.1

With no SRM OPERABLE, actions to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, actions shall be continued until an SRM is restored to OPERABLE status.

B.2

With no SRM OPERABLE, there is no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the SRMs are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to verify that the required boron concentration exists.

(continued)

BASES (continued)

LCO (continued)

The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

The LCO is modified by two Notes. With the upper guide structure removed from the reactor vessel Note 1 allows the required operating SDC loop to be removed from service for up to 2 hours in each 8 hour period, provided that:

a. The maximum RCS temperature is maintained ≤ 140°F.
b. No operations are permitted that would dilute the RCS boron concentration to less than that required to meet the minimum required boron concentration of LCO 3.9.1.
c. The capability to close the containment penetrations with direct access to the outside temperature within the calculated time to boil is maintained.
d. The reactor cavity water level is maintained ≥ 20 feet above the top of the reactor pressure vessel flange, or, for core alterations, ≥ 23 feet above the top of the reactor pressure vessel flange.

This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles, RCS to SDC isolation valve testing, and inservice testing of LPSI system components. During this 2 hour period, decay heat is removed by natural convection to the large mass of water in the refueling canal.

Note 2 allows Operations to use a containment spray pump in place of a low pressure safety injection pump to provide shutdown cooling flow.

APPLICABILITY

One SDC loop must be in operation in MODE 6, with the water level ≥ 20 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the SDC System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). SDC loop requirements in MODE 6, with the water level < 20 ft above the top of the reactor vessel flange, are located in LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation — Low Water Level."

ACTIONS

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

(continued)

BASES (continued)

ACTIONS (continued)

A.1

If SDC loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. 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 what would be 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.

A.2

If SDC loop requirements are not met, actions shall be taken immediately to suspend loading irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 20 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase the decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If SDC loop requirements are not met, actions shall be initiated and continued in order to satisfy SDC loop requirements.

A.4

If SDC loop requirements are not met, all containment penetrations to the outside atmosphere must be closed to prevent fission products, if released by a loss of decay heat event, from escaping the containment building. The 4 hour or within the calculated time to boil Completion Time allows fixing most SDC problems without incurring the additional action of violating the containment atmosphere.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

When two SDC loops are operable and if one SDC loop becomes inoperable, actions shall be immediately initiated and continued until the SDC loop is restored to OPERABLE status and to operation, or until ≥ 20 ft of water level is established above the reactor vessel flange. When the water level is established at ≥ 20 ft above the reactor vessel flange, the Applicability will change to that of LCO 3.9.4, "Shutdown Cooling and Coolant Circulation – High Water Level," and only one SDC loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

When one loop of the SDC is operable with requirements 1-8 satisfied and the SDC loop becomes inoperable or any of the 8 requirements are not met, actions shall be immediately initiated to establish a water level > 20 feet above the reactor flange. When the water level is established at > 20 feet above the reactor vessel flange, the applicability will change to that of LCO 3.9.4, "Shutdown Cooling and Coolant Circulation-High Water Level," and only one SDC loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

C.1

If no SDC loop is in operation or no SDC loops are OPERABLE, there will be no forced circulation to provide mixing to establish uniform boron concentrations. 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 what would be 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.

(continued)

BASES (continued)

ACTIONS (continued)

C.2

If no SDC loop is in operation or no SDC loops are OPERABLE, actions shall be initiated immediately and continued without interruption to restore one SDC loop to OPERABLE status and operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE SDC loops and one operating SDC loop should be accomplished expeditiously.

C.3

If SDC loops requirements are not met, all containment penetrations to the outside atmosphere must be closed to prevent fission products, if released by a loss of decay heat event, from escaping the containment building. The 4 hour or within the calculated time to boil Completion Time allows fixing most SDC problems without incurring the additional action of violating the containment atmosphere.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one SDC loop is operating and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, this Surveillance demonstrates that the other SDC loop is OPERABLE.

In addition, during operation of the SDC loop with the water level in the vicinity of the reactor vessel nozzles, the SDC loop flow rate determination must also consider the SDC pump suction requirements. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator to monitor the SDC System in the control room.

Verification that the required loops are OPERABLE and in operation ensures that loops can be placed in operation as needed, to maintain decay heat and retain forced circulation. The Frequency of 12 hours is considered reasonable, since other administrative controls are available and have proven to be acceptable by operating experience.

REFERENCE

1. UFSAR, Section 7.4.