April 12, 2000

Mr. C. Lance Terry
Senior Vice President &
Principal Nuclear Officer
TXU Electric Company
Attn: Regulatory Affairs Department
P. O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION, UNITS 1 AND 2 - REPLACEMENT TECHNICAL SPECIFICATION BASES PAGES (TAC NOS. MA8557 AND MA8558)

Dear Mr. Terry:

By letter dated March 17, 2000, you submitted changes to the Bases for the Comanche Peak Steam Electric Station, Units 1 and 2 (CPSES) Technical Specifications (TS). The Bases changes involve both changes made via license amendments, with prior U.S. Nuclear Regulatory Commission (NRC) approval, and those made via 10 CFR Part 50, Section 50.59(a)(1), without prior NRC approval.

Enclosed are the revised TS Bases pages that the NRC staff will use to update its copy of the CPSES TS Bases.

Sincerely,

/RA/
David H. Jaffe, Senior Project Manager, Section 1
Project Directorate IV & Decommissioning
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-445 and 50-446

Enclosure: Bases pages

cc w/encl: See next page

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cc:

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
P. O. Box 2159
Glen Rose, TX 76403-2159

Regional Administrator, Region IV
U.S. Nuclear Regulatory Commission
611 Ryan Plaza Drive, Suite 400
Arlington, TX 76011

Mrs. Juanita Ellis, President
Citizens Association for Sound Energy
1426 South Polk
Dallas, TX 75224

Mr. Roger D. Walker
Regulatory Affairs Manager
TXU Electric
P. O. Box 1002
Glen Rose, TX 76043

George L. Edgar, Esq.
Morgan, Lewis & Bockius
1800 M Street, N.W.
Washington, DC 20036-5869

Honorable Dale McPherson
County Judge
P. O. Box 851
Glen Rose, TX 76043

Office of the Governor
ATTN: John Howard, Director
Environmental and Natural
Resources Policy
P. O. Box 12428
Austin, TX 78711

Arthur C. Tate, Director
Division of Compliance & Inspection
Bureau of Radiation Control
Texas Department of Health
1100 West 49th Street
Austin, TX 78756-3189

Jim Calloway
Public Utility Commission of Texas
Electric Industry Analysis
P. O. Box 13326
Austin, TX 78711-3326

COMANCHE PEAK STEAM ELECTRIC STATION
TECHNICAL SPECIFICATIONS BASES
INSTRUCTION SHEET

The following instructional information is provided for guidance in inserting the change pages for the Technical Specification Bases.

Discard the old sheet and insert the new sheets, as listed below.

REMOVE	INSERT
B 2.0-2	B 2.0-2
B 2.0-3	B 2.0-3
B 3.1-2	B 3.1-2
B 3.1-3	B 3.1-3
B 3.1-28	B 3.1-28
B 3.1-41	B 3.1-41
B 3.1-45	B 3.1-45
B 3.2-31	B 3.2-31
B 3.3-1	B 3.3-1
B 3.3-3 thru B 3.3-6	B 3.3-3 thru B 3.3-6
B 3.3-8	B 3.3-8
B 3.3-64 thru B 3.3-69	B 3.3-64 thru B 3.3-69
B 3.3-71	B 3.3-71
B 3.3-72	B 3.3-72
B 3.3-98	B 3.3-98
B 3.3-120 thru B 3.4-122	B 3.3-120 thru B 3.4-122
B 3.4-2 thru B 3.4-4	B 3.4-2 thru B 3.4-4
B 3.4-10	B 3.4-10

Enclosure

REMOVE	INSERT
B 3.4-42	B 3.4-42
B 3.4-81 thru B 3.4-84	B 3.4-81 thru B 3.4-84
B 3.4-86	B 3.4-86
B 3.4-91	B 3.4-91
B 3.5-18	B 3.5-18
B 3.5-19	B 3.5-19
B 3.5-24 thru B 3.5-28	B 3.5-24 thru B 3.5-28
B 3.6-21a	B 3.6-21a
B 3.7-33	B 3.7-33
B 3.7-61	B 3.7-61
B 3.7-69	B 3.7-69
B 3.7-70	B 3.7-70
B 3.7-96	B 3.7-96
B 3.8-4	B 3.8-4
B 3.8-16	B 3.8-16
B 3.8-17	B 3.8-17
B 3.8-22 thru B 3.8-28	B 3.8-22 thru B 3.8-28
B 3.8-39 thru B 3.8-45	B 3.8-39 thru B 3.8-45
B 3.8-53	B 3.8-53
B 3.8-55	B 3.8-55
B 3.8-55a	B 3.8-55a
B 3.8-66	B 3.8-66
B 3.8-69	B 3.8-69

REMOVE	INSERT
B 3.8-76	B 3.8-76
B 3.8-78	B 3.8-78
B 3.9-8	B 3.9-8
B 3.9-13	B 3.9-13
--	EPL-i
(EPL) 1 thru 10	EPL-1 thru EPL-10

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

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

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

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

Protection for these reactor core SLs is provided by the appropriate operation of the RPS and the steam generator safety valves. | 4

| 4

The SLs represent a design requirement for establishing the RPS Allowable Values identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," and the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

(continued)

BASES

SAFETY LIMITS

The reactor core SLs are established to preclude violation of the following fuel design criteria: 4

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

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature N-16 reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation.

Appropriate functioning of the RPS and the steam generator safety valves ensure that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs. Limits on process variables are developed both to protect the reactor core SLs and for compliance with the additional restrictions on hot leg enthalpy and vessel exit quality. The Reactor Core Safety Limit figures, provided in the COLR, reflect these process variable limits.

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Allowable Values for the reactor trip functions are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on a scram. | 1

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

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

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm average fuel pellet enthalpy at the hot spot for the rod ejection accident); and

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

The most limiting accidents for the SDM requirements area main steam line break (MSLB) and boron dilution accidents, as described in the accident analysis (Ref. 2). | 7

The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As the initial RCS temperature decreases, the severity of an MSLB decreases until MODE 5 is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest. The shutdown margin must be adequate to allow sufficient time for the reactor operators to detect an inadvertent boron dilution and initiate appropriate action to prevent a complete loss of shutdown margin.

7

(continued)

BASES

ACTIONS

D.1.1 and D.1.2 (continued)

adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases or LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the required pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. If the rod position deviation monitor is inoperable, the Frequency is increased to 4 hours per TRM requirement TRS 13.1.37.1 which accomplishes the same goal. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected. | 7

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.6.2

Verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to ensure OPERABILITY and to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

SR 3.1.6.3

There is a potential that, with only a limit on rod insertion, the RCCAs could be placed in a sequence or overlap position, perhaps during troubleshooting activities or other abnormal plant conditions, that would violate core flux peaking factors while still satisfying the limits on rod insertion. This scenario is most likely to occur at reduced power following an automatic runback or due to an administrative power reduction in response to some rod control abnormality.

This surveillance ensures that the rod configuration across the core for any given operating condition will not result in unanalyzed peaking factors. The surveillance is not designed to test or verify the function of the Rod Control sequence and overlap circuits. In practice, this surveillance will be satisfied as long as the rod positions are in the positions specified in the COLR, regardless of the operability of the sequence and overlap circuits. The intent is to check the rod position to verify that the rods are in the expected positions as described in the COLR. If all rods are out of the core when the check is made, then rod sequence and overlap limits are satisfied for the purpose of this surveillance. At all power levels, the rod positions should conform to the requirements of the COLR for rod sequence and overlap. Implicit within the LCO is the assumption that bank sequence and overlap must be maintained during rod movement. When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2. | 1

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The control rod position indicator channels satisfy Criterion 2 of 10CFR50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that the DRPI System and Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The DRPI System, on either full accuracy or half accuracy, indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits"; and

b. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System. | 4

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

(continued)

BASES

ACTIONS

A.5 (continued)

Required Action A.5 is modified by two Notes. Note 1 states that the excore detectors are not normalized to restore to restore QPTR to within limits until after the evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). Note 2 states that if Required Action A.5 is performed, then Required Action A.6 shall be performed. Required Action A.5 normalizes the excore detectors to restore QPTR to within limit, which restores compliance with LCO 3.2.4. Thus, Note 2 prevents exiting the Actions prior to completing flux mapping to verify peaking factors per Required Action A.6. These notes are intended to prevent any ambiguity about the required sequence of actions. | 1 | 1

A.6

Once the excore detectors are normalized to restore QPTR to within limit (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of achieving equilibrium conditions at RTP. As an added precaution, if the core power does not reach equilibrium conditions at RTP within 24 hours but is increased slowly, then the peaking factor surveillances must be performed within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1. This Completion Time is intended to allow adequate time to increase THERMAL POWER to above the limits of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances must be completed when the excore detectors have been normalized to restore QPTR to within limit (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to restore QPTR to within limit.

(continued)

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

For the purposes of demonstrating compliance with 10CFR50.36, the Technical Specifications must specify Limiting Safety System Settings (LSSS). The Allowable Value specified in Table 3.3.1-1 serves as the LSSS. The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs). 7

The Allowable Value serves as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the established trip setpoint calibration tolerance band in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the allowances of the uncertainty terms assigned.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the departure from nucleate boiling ratio (DNBR) limit;

2. Fuel centerline melt shall not occur; and

3. The RCS pressure Safety Limit of 2735 psig shall not be exceeded.

(continued)

BASES

BACKGROUND (continued)

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor is determined by either "as-found" calibration data evaluated during CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.. 7

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

(continued)

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy.

The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 3). The actual number of channels required for each unit parameter is specified in Reference 1.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without initiating protective action, unless a trip condition actually exists. This arises from the use of coincidence logic in generating reactor trip signals and from the capability to bypass a partial protective action while in test.

Allowable Values and Trip Setpoints

7

(continued)

BASES

BACKGROUND

Allowable Values and Trip Setpoints (continued)

The trip setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits. | 7

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. The essential elements of the methodology are described in Reference 9. Changes in accordance with this methodology have been reviewed by the staff in the original Unit 2 Technical Specifications and in several subsequent license amendments (e.g., amendments 21/7 and 22/8 to the Unit 1/Unit 2 Technical Specifications). The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE. The trip setpoint is the alue at which the bistable is set and is the expected value to be achieved during calibration. The trip setpoint value ensures the LSSS and the safety analysis limits are met for the time period of the surveillance interval when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The trip setpoint value of Table B3.3-1.1 is therefore considered a "nominal" value (i.e., expressed as a vaolue without inequalities) for the purposes of COT and CHANNEL CALIBRATION. | 7

Trip setpoints consistent with the requirements of the Allowable Value ensure that design limits are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS. | 7

(continued)

BASES

BACKGROUND

Allowable Values and Trip Setpoints (continued)

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

7

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The SSPS performs the decision logic for actuating a reactor or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

(continued)

BASES

BACKGROUND

Reactor Trip Switchgear (continued)

that can automatically test the decision logic matrix Functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to maintain the applicable Safety Limits during all AOOs and mitigates the consequences of DBAs in all MODES in which the Rod Control system is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 2 takes credit for most RTS trip Functions. RTS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backup or diverse trips to RTS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

A channel is OPERABLE with a trip setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the calibration tolerance band of the Nominal Trip Setpoint. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions. 7

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection,

(continued)

Table B 3.3.1-1 (page 1 of 2)
Reactor Trip System Setpoints

Function	Nominal Trip Setpoint	
1. Manual Reactor Trip	N/A	
2. a. Power Range Neutron Flux, High	109% RTP	| 7
2. b. Power Range Neutron Flux, Low	25% RTP	| 7
3. Power Range Neutron Flux Rate, High Positive Rate	5% RTP with a time constant ≥ 2 seconds	| 7
4. Intermediate Range Neutron Flux, High	25% RTP	| 7
5. Source Range Neutron Flux, High	10^5 cps	| 7
6. Overtemperature N-16	See Note 1, Table 3.3.1-1	
7. Overpower N-16	112% RTP (Unit 1) 110% RTP (Unit 2)	| 7
8. a. Pressurizer Pressure, Low	1880 psig	| 7
8. b. Pressurizer Pressure, High	2385 psig	| 7
9. Pressurizer Water Level - High	92% span	| 7
10. Reactor Coolant Flow - Low	90% of nominal flow	| 7
11. Not Used.		
12. Undervoltage RCPs	4830 volts	| 7
13. Underfrequency RCPs	57.2 Hz	| 7

(continued)

Table B 3.3.1-1 (page 2 of 2)
Reactor Trip System Setpoints

Function	Nominal Trip Setpoint	
14. Steam Generator Water Level - Low-Low	25% NR (Unit 1) 35.4% NR (Unit 2)	7
15. Not Used.		
16. Turbine Trip		7
a. Low Fluid Oil Pressure	59 psig	7
b. Turbine Stop Valve Closure	1% open	7
17. SI Input form ESFAS	NA	
18. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	1×10^{-10} amps	7
b. Low Power Reactor Trips Block, P-7	NA	
c. Power Range Neutron Flux, P-8	48% of RTP	
d. Power Range Neutron Flux, P-9	50% of RTP	7
e. Power Range Neutron Flux, P-10	10% of RTP	
f. Turbine First Stage Pressure, P-13	10% turbine power	
19. Reactor Trip Breakers	NA	
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	NA	
21. Automatic Trip Logic	NA	

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;
- Signal processing equipment including 7300 process Instrumentation and Control system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/ control room/miscellaneous indications; and
- Solid State Protection System (SSPS) including input, logic, and output bays: initiates the proper unit shutdown or engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

The Allowable Value in conjunction with the trip setpoint and LCO establishes the threshold for ESFAS action to prevent exceeding acceptable limits such that the consequences of Design Basis Accidents (DBAs) will be acceptable. 7

The Allowable Value is considered a limiting value such that a channel is OPERABLE if the setpoint is found not to exceed the Allowable Value during the CHANNEL OPERATIONAL TEST (COT). Note that, although the channel is OPERABLE under these circumstances, the ESFAS setpoint must be left adjusted to a value within the established calibration tolerance band of the ESFAS setpoint in accordance with the uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the allowances of the uncertainty terms assigned.

(continued)

BASES

BACKGROUND (continued)

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values is determined by either "as-found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK. 7

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of- two logic.

(continued)

BASES

BACKGROUND

Signal Processing Equipment (continued)

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Allowable Values and Trip Setpoints

7

The trip setpoints used in the bistables are based on the analytical limits stated in Reference 3. The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservative with respect to the analytical limits. Detailed descriptions of the methodologies used to calculate the trip setpoints, including their explicit uncertainties, are provided in the setpoint calculations. The methodology to derive the trip setpoints is based upon combining all of the uncertainties in the channels. The essential elements of the methodology are described in Reference 9. 7

(continued)

BASES

BACKGROUND

Allowable Values and Trip Setpoints (continued)

Changes in accordance with this methodology have been reviewed by the staff in the original Unit 2 Technical Specifications and in several subsequent license amendments (e.g., amendments 21/7 and 22/8 to the Unit 1/Unit 2 Technical Specifications). The actual nominal ESFAS setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. The Allowable Value serves as the Technical Specification operability limit for the purpose of the COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE. | 7 | 7

Setpoints adjusted consistent with the requirements of the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed. | 7

The ESFAS setpoint is the value at which the bistable is set and is the expected value to be achieved during calibration. The ESFAS setpoint value ensures the safety analysis limits are met for the time period of the surveillance interval when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as left" setpoint value is within the band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration + comparator setting uncertainties). The ESFAS setpoint value of Table B3.3.2-1 is therefore considered a "nominal" value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION. | 7

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section. | 7

(continued)

BASES

BACKGROUND

Solid State Protection System (continued)

and slave relays are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented by the SLAVE RELAY TEST circuit, and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure — Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

A channel is OPERABLE with a setpoint value outside its calibration tolerance band provided the trip setpoint "as-found" value does not exceed its associated Allowable Value and provided the trip setpoint "as-left" value is adjusted to a value within the calibration tolerance band of the Nominal Trip Setpoint. A trip setpoint may be set more conservative than the Nominal Trip Setpoint as necessary in response to plant conditions. 7

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS. The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (e.g., coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

These functions are necessary to mitigate the effects of certain high energy line breaks (HELBs) both inside and outside of containment as described in the FSAR [Ref. 3]. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Ventilation Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps;

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

7. Automatic Switchover to Containment Sump (continued)

pumps draw the water from the containment recirculation sump, the RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the suction of the other ECCS pumps. Switchover from the RWST to the containment sump must occur before the RWST Empty setpoint. Switchover of the containment spray pumps from the RWST to the containment sump is performed manually after completion of ECCS switchover, but before the | 8
Empty setpoint is reached. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ESF pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. Raising the nominal RWST level at which Operations | 8
starts switchover (45%) would require prior NRC approval. This ensures the reactor remains shut down in the recirculation mode.

a. Automatic Switchover to Containment Sump — Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Automatic Switchover to Containment Sump — Refueling Water Storage Tank (RWST) Level — Low Low Coincident With Safety Injection

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low low level in the RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the ECCS injection phase of the LOCA. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability.

(continued)

Table B 3.3.2-1 (page 1 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint	
1. Safety Injection		
a. Manual Initiation	NA	
b. Automatic Actuation Logic and Actuation Relays	NA	
c. Containment Pressure - High 1	3.2 psig	| 7
d. Pressurizer Pressure - Low	1820 psig	| 7
e. Steam Line Pressure - Low	605 psig $\tau_1 \geq 50$ seconds $\tau_2 \leq 5$ seconds	| 7
2. Containment Spray		
a. Manual Initiation	NA	
b. Automatic Actuation Logic and Actuation Relays	NA	
c. Containment Pressure - High 3	18.2 psig	| 7
3. Containment Isolation		
a. Phase A Isolation		
(1) Manual Initiation	NA	
(2) Automatic Actuation Logic and Actuation Relays	NA	
(3) Safety Injection	See Function 1	

(continued)

Table B 3.3.2-1 (page 2 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint	
3. Containment Isolation (continued)		
b. Phase B Isolation		
(1) Manual Initiation	NA	
(2) Automatic Actuation Logic and Actuation Relays	NA	
(3) Containment Pressure - High 3	18.2 psig	| 7
4. Steam Line Isolation		
a. Manual Initiation	NA	
b. Automatic Actuation Logic and Actuation Relays	NA	
c. Containment Pressure - High 2	6.2 psig	| 7
d. Steam Line Pressure		
(1) Low	605 psig $\tau_1 \geq 50$ seconds $\tau_2 \leq 5$ seconds	| 7
(2) Negative Rate - High	100 psi $\tau \geq 50$ seconds	| 7
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	NA	
b. SG Water Level - High-High (P-14)	82.4% NR (Unit 1) 81.5% NR (Unit 2)	| 7 |
c. Safety Injection	See Function 1.	

(continued)

Table B 3.3.2-1 (page 3 of 3)
ESFAS Trip Setpoints

Function	Nominal Trip Setpoint	
6. Auxiliary Feedwater		
a. Automatic Actuatin Logic and Actuation Relays (SSPS)	NA	
b. Not Used		
c. SG Water Level - Low-Low	25% NR (Unit 1) 35.4% NR (Unit 2)	| 7
d. Safety Injection	See Function 1.	
e. Loss of Power	NA	
f. Not Used		
g. Trip of All Main Feedwater Pumps	NA	
h. Not Used.		
7. Automatic Switchover to Containment Sump		
a. Automatic Actuation Logic and Actuation Relays	NA	
b. Refueling Water Storage Tank (RWST) Level - Low-Low Coincident with Safety Injection	45.0% span	| 8
8. ESFAS Interlocks		
a. Reactor Trip, P-4	NA	
b. Pressurizer Pressure, P-11	1960 psig	| 7

BASES (continued)

APPL ICABLE SAFETY ANALYSES

Operation for significant periods of time outside the limits on RCS flow, pressurizer pressure and average temperature increases the likelihood of a fuel cladding failure if a DNB limited event were to occur.

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criterion. The transients analyzed for include loss of coolant flow events and dropped rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.7, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit and the RCS average temperature limit specified in the COLR correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty. These uncertainties are based on the use of control board indications. | 4

The RCS DNB parameters satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables— pressurizer pressure, RCS average temperature, and RCS total flow rate — to ensure the core operates within the limits assumed in the safety analyses. These variables are considered in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, based on maximum analyzed steam generator tube plugging, is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient. | 4

RCS total flow rate contains a measurement error of 1.8% based on performing a precision heat balance and using the result to normalize the RCS flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner.

(continued)

BASES

LCO (continued)

Any fouling that might significantly bias the flow rate measurement can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling. CPSES also uses the Transit Time Flow Meter (TTFM) to measure the volumetric RCS hot leg flow rate. The use of the TTFM results in an RCS flow measurement which is more accurate and less sensitive to RCS fluid conditions than other methods.

The numerical values for pressure, temperature, and flow rate specified in the COLR have been adjusted for instrument error. | 4

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded. | 4

(continued)

BASES (continued)

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and reduce the potential for violation of the accident analysis limits.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

This condition is modified by a note that states that this condition is only applicable prior exceeding 85% RTP after a refueling outage. This applicability is consistent with the required performance of SR 3.4.1.4. The purpose of this condition is to provide instructions should SR 3.4.1.4 not be completed satisfactorily during the initial power ascension following a refueling outage. If, for any reason, SR 3.4.1.4 is performed during a mid-cycle outage, and verification of the RCS flow can not be verified, Condition A should be entered. | 1

The precision RCS flow measurement is performed following each refueling outage, or other outage in which an activity was performed that could affect the RCS flow indication. The precision flow measurement is required to be performed prior to exceeding 85% RTP, and is predicated upon the verification that:

- measured RCS flow based on elbow tap differential pressure measurement prior to Mode 1 is within 20% of the expected RCS flow;

(continued)

BASES

APPLICABILITY (continued)

so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

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

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

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

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

REFERENCES

1. FSAR, Chapter 15.

BASES (continued)

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

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

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps 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.

(continued)

BASES (continued)

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

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

b. Unidentified LEAKAGE

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

c. Identified LEAKAGE

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

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs) (Unit 2 only) | 5

Total primary to secondary LEAKAGE amounting to 1 gpm through all SGs produces acceptable offsite doses in the accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

(continued)

BASES

LCO (continued)

e. Primary to Secondary LEAKAGE through Any One SG

For Unit 2, the 500 gallons per day limit on one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line rupture. If leaked through many cracks, the cracks are very small, and the above assumption is conservative. 5

For Unit 1, maintaining an operating leakage of 150 gpd per steam generator (0.1 gpm - at room temperature) (600 gpd total) minimizes the potential for a large leakage event during a main steam line break. Based on the non-destructive examination uncertainties, bobbin coil voltage distribution and crack growth rate from the previous inspection, the expected leak rate following a steam line break is limited to below 27.79 gpm (calculated at room temperature conditions) for Comanche Peak Unit 1 in the faulted loop. Maintaining leakage within the 27.79 gpm limit will ensure that offsite doses will remain within 10 CFR Part 100 guidelines and within control room dose (GDC-19) guidelines. Leakage in the intact loops will be limited to a leak rate of 150 gpd. If the projected end-of-cycle distribution of crack indications results in primary-to-secondary leakage greater than 27.79 gpm in the faulted loop during a postulated steam line break event, additional tubes must be removed from service in order to reduce steam line break leakage to below this limit. 5

The leakage limits incorporated in 5.5.9 are more restrictive than the standard operating license limits and are intended to provide an additional margin to accommodate a crack which might grow at a greater than expected rate or unexpectedly extend outside the thickness of the tube support plate. Hence, the reduced leakage limit, when combined with an effective leak rate monitoring program, provides additional assurance that should a significant leak be experienced in service, it will be detected, and the plant shutdown in a timely manner.

APPLICABILITY

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

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

(continued)

BASES

APPLICABILITY (continued)

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

ACTIONS

A.1

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

B.1 and B.2

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

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

(continued)

BASES

ACTIONS

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.

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

Steady state operation is required to perform a proper inventory balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature (T_{avg} changing by less than 5°F/hour), power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows. An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

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

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line can effect the overall leakage rate determined by RCS water inventory balance of SR 3.4.13.1 and therefore may be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE". A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight. | 7

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

In addition, testing must be performed once after the check valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed 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 24 hours after the check valve has been reseated (except as provided by Note 1). Within 24 hours | 1
is a reasonable and practical time limit for performing this test after opening or reseating a check 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 complementary 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 except for RHR isolation valves 8701A, 8701B, | 1
8702A and 8702B. This exception is allowed since these RHR valves |
have control room position indication, inadvertent opening interlocks and a system high pressure alarm. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

Testing is not required for the RHR suction isolation valves more frequently than 18 months as these valves are motor-operated with control room position indication, inadvertent opening interlocks and system high pressure alarms.

(continued)

BASES

ACTIONS (continued)

B.1

With one or more trains inoperable, for reasons other than one inoperable centrifugal charging pump, and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

100% of the ECCS flow equivalent to a single OPERABLE ECCS train is considered available if the following conditions are met: 1) There must be one fully OPERABLE centrifugal charging pump, one fully OPERABLE safety injection pump and one fully OPERABLE RHR pump with associated heat exchanger at a minimum. 2) The flow paths associated with each pump and heat exchanger for which credit is being taken must be OPERABLE in the injection and recirculation flow paths. 3) ECCS system alignment, with the exception of isolation valves for inoperable pumps and heat exchangers must be normal. 4) All automatic functions and interlocks must be OPERABLE for the components for which credit is being taken. 5) All support systems for the pumps and heat exchangers for which credit is being taken are OPERABLE. 6) The combination of components must be such that a transition from cold leg to hot leg recirculation can be accomplished. | 1

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

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 this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

(continued)

BASES

ACTIONS

B.1 (continued)

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

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

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power by a control board switch in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in References 6 and 7, that can disable the function of both ECCS trains and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely. As noted in LCO Note 1, both Safety Injection pump flow paths may each be isolated for two hours in MODE 3 by closure of one or more of these valves to perform pressure isolation valve testing.

(continued)

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS — Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS — Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of two separate subsystems: centrifugal charging (high head) and residual heat removal (RHR) (low head).

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of a centrifugal charging subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS 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 deliver its flow to the RCS hot and cold legs.

This LCO is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant 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 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation — High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation — Low Water Level."

(continued)

BASES (continued)

ACTIONS

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop.

If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With no ECCS high head subsystem OPERABLE, due to the inoperability of the centrifugal charging pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS high head subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

(continued)

BASES

ACTIONS (continued)

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

BASES

ACTIONS

C.1 and C.2 (continued)

There are three types of penetrations to which Condition C applies: 1

1. All GDC-57 penetrations Main Steam (e.g., MSIVs, MSIV bypasses, SG Blowdowns, N2 supplies, MS Drains, SG Sample Lines) Feedwater (e.g., Feedwater supplies to SGs, AFW supplies to SGs, N2 supplies, Feedwater Bypass Lines, Feedwater Preheater Bypass Lines), CCW Supply and Return From Excess Letdown & R.C. Drain Tank Heat Exchanger, Unit 1 PAL, Airlock Hydraulic System). DBD-ME-013 Attachment 1 lists each such valve with the GDC-57 criterion and gives the valve arrangement sketch and the Flow Diagram reference (e.g., MS and FW items 1 thru 30, 73, 76, 79 and 82; CCW items 111 and 112).

2. Special case GDC-56 for the emergency sump isolation (DBD-ME-013 Attachment 1 RHR and CT items 125, 126, 127, and 128) which have a single containment isolation valve outside containment and a closed system outside containment.

3. Special case GDC-55 RHR suction line (DBD-ME-013 Attachment 1 RHR items 33 and 34) which have a single containment isolation valve inside containment and a closed system outside containment.

All other penetrations (GDC-55 and 56) have double isolation valves.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 2). The motor driven pumps should develop a differential pressure of ≥ 1380 psid at a flow of ≥ 430 gpm. The turbine driven pump should develop a differential pressure of ≥ 1438 psid at a flow of ≥ 860 gpm. Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow through a test line. This test confirms one point on the pump design curve and is indicative of overall performance. Instrument uncertainty is not included in the above flow and differential pressure values but is addressed in the surveillance testing procedure. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code, Section XI (Ref. 2) (only required at 3 month intervals) satisfies this requirement. | 4 | 4 | 4

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 insufficient steam pressure to perform the test.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation generated by an auxiliary feedwater actuation signal. The Steam Generator Blowdown, Steam Generator Blowdown Sample, and Feedwater Split Flow Bypass valves close on an auxiliary feedwater actuation to ensure auxiliary feedwater is delivered to the steam generator upper nozzles and is retained in the steam generator for decay heat removal. The AFW flow control valves trip to auto (open) on an auxiliary feedwater actuation to ensure full flow is delivered to each steam generator flow path. The steam admission valves open to supply

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.3

This SR verifies that each CREFS train starts and operates on an actual or simulated Safety Injection, Loss-of-Offsite Power, or Intake Vent-High Radiation actuation signal. The Frequency of 18 months is specified in Regulatory Guide 1.52 (Ref. 3). Each actuation signal must be verified (overlapping testing is acceptable).

SR 3.7.10.4

This SR verifies the integrity of the control room enclosure, and the assumed inleakage rates of the potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper functioning of the CREFS. During the emergency recirculation mode of operation, the CREFS is designed to pressurize the control room ≥ 0.125 inches water gauge positive pressure with respect to adjacent areas in order to prevent unfiltered inleakage. The CREFS is designed to maintain this positive pressure with one train at a makeup flow rate of ≤ 800 cfm. The Frequency of 18 months on a STAGGERED TEST BASIS is consistent with the guidance provided in NUREG-0800 (Ref. 4). | 1

REFERENCES

1. FSAR, Sections 2.2, 6.4, 6.5, 7.3, and 9.4.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.52, Rev. 2.
4. NUREG-0800, Section 6.4, Rev. 2, July 1981.

BASES

LCO

Two independent and redundant trains of the PPVS are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train coincident with loss of offsite power. Total system failure could result in the atmospheric release from the ESF equipment leakage exceeding regulatory limits in the event of a Design Basis Accident (DBA).

PPVS is considered OPERABLE when the individual components necessary to maintain the ESF filtration are OPERABLE in both trains.

A PPVS Train is considered OPERABLE when it's individual components necessary to maintain the ESF filtration are operable such that the required negative pressure can be maintained in the Auxiliary and Safeguards buildings. Note: If one of the two ESF filtration units in a train can maintain the required negative pressure alone, it would satisfy the operability requirements provided: 1

1. The out of service/inoperable unit is isolated or the exhaust fan is prevented from automatic starting to ensure that no unfiltered exhaust to the environment occurs, and,

2. If the OPERABLE filter unit in a train is CPX-VAFUPK-15 or 16 the exhaust fan of the out of service/inoperable unit shall be prevented from starting or placed under administrative control to secure the fan in the event of an actual ESF actuation. This will ensure the fan room design heat loads are not exceeded.

3. Surveillance Requirement 4.7.12.4 has been satisfactorily performed within the required interval, in the one unit per train configuration for the particular unit concern in order to demonstrate the negative pressure function.

A PPVS ESF Filtration Unit is considered OPERABLE when its associated:

a. Fan is OPERABLE;

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

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

(continued)

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the PPVS is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

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

In MODE 5 or 6 or during movement of irradiated fuel assemblies, the PPVS is not required to be operable since it is not required for mitigation of fuel handling accidents [Ref. 3].

ACTIONS

A.1

With one or more ESF Filtration trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel buildings ≥0.05 inch water gauge, action must be taken to restore OPERABLE status within 30 days. During this time the ESF Filtration trains must maintain ≥ 0.01 inch water gauge. This negative pressure will still ensure that unfiltered air does not escape the pressure envelope.

The 30 day Completion Time is appropriate because an adequate negative pressure envelope is still maintained.

B.1

With one or more ESF Filtration trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings ≥0.01 inch water gauge, action must be taken to restore OPERABLE status within 7 days.

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period and the design of the buildings included within the negative pressure envelope. The buildings are designed such that the rooms with sources of potential ECCS leakage are below grade or internal to the structure of these buildings thus providing a buffer zone to external leakage.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.20.1

Verifying each require EFCU operates for ≥ 1 continuous hour ensures that they are OPERABLE.

SR 3.7.20.2

Verifying each UPS A/C train operates for ≥ 1 hour ensures that they are OPERABLE and that all associated controls are functioning properly.

SR 3.7.20.3

This SR verifies that the each UPS A/C train starts and operates on an actual or simulated Safety Injection actuation signal and on an actual or simulated Blackout actuation signal. The 18 month frequency is consistent with the typical refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint. | 1

REFERENCES

1. FSAR, Section 9.4C.8.

BASES

LCO (continued)

Offsite circuit #1 is fed from the 138 kv switchyard and offsite circuit # 2 is fed from the 345 kv switchyard. Circuit #1 is the preferred source for Unit 2 and alternate source for Unit 1. Circuit # 2 is the preferred source for Unit 1 and alternate source for Unit 2. Each offsite circuit can supply 6.9 kv Train A and Train B ESF busses for both Unit 1 and Unit 2.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on receipt of bus undervoltage signal. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to ready-to-load status on an SI signal while operating in parallel test mode. | 1

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

The offsite AC sources must be separate and independent (to the extent possible). For the onsite 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 OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESF bus, is required to have an operable transfer mechanism to that bus to support operability of that circuit.

Each circuit of offsite source can feed both trains. Preferred source breakers are normally closed and alternate source breakers are normally open. Each bus has automatic capability to transfer to the alternate source on loss of preferred source.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7

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

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

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. For SR 3.8.1.2 and SR 3.8.1.7 testing, the diesel should be started from ambient conditions which means the diesel engine is cold or at a temperature consistent with manufacturer's recommendations. 1

The DG shall start using one of the following signals: 1) Manual, 2) Simulated or actual safeguards bus undervoltage, 3) Safety Injection simulated or actual signal in conjuction with a simulated or actual loss of offsite power signal, or 4) a Safety Injection simulated or actual signal by itself.

For SR 3.8.1.2, in order to reduce stress and wear on diesel engines, the manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions, accelerates to 441 RPM, and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

The 10 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

Since SR 3.8.1.7 requires a 10 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 is employed, is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance. 3

The 31 day Frequency for SR 3.8.1.2, is consistent with Regulatory Guide 1.9 (Ref. 3) and Generic Letter 94-01 (Ref. 14). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. 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 DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3) and Generic Letter 94-01 (Ref. 14).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 safety functions encountered from the loss of offsite power, including shedding of the nonessential loads, energization of the emergency buses in ≤ 10 seconds after auto-start signal, and energization of the respective loads from the DG. It further demonstrates the capability of the DG to automatically maintain the required steady state voltage and frequency. 4

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

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

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (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. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. 1 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts, achieves and maintains the required voltage and frequency within the specified time (10 seconds) from the safety injection signal and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

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

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. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. | 1 | 1

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a DG emergency start which occurs from either a loss of voltage or an SI actuation test signal. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG. | 5

The 18 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 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by a Note. The Note says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to approximately 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 purposes of the 2 hour run, the minimum load is approximately 110% of the 6300 kW maximum design load in lieu of the 7000 kW continuous rating. The DG start for this Surveillance can be performed either from ambient 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. 4

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 18 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 transients due to changing bus loads do not invalidate this test. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.15 (continued)

The generator voltage shall be between 6480 V and 7150 V and frequency shall be 60± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

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

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3) this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and the DG can be returned to ready to load status when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready to load status when the DG is at rated speed and voltage, the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset. | 4

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), paragraph 2.a.(6), and takes into consideration unit conditions required to perform the Surveillance.

This SR is modified by a Note. The Note says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

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

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

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

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

This SR is modified by a Note. The Note says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

SR 3.8.1.18

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

The Frequency of 18 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. The Note says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

SR 3.8.1.19

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

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

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. | 1 | 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed (441 rpm) within the specified time when the DGs are started simultaneously.

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

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions for a DG mean that the diesel is shutdown but is ready for either a manual or automatic start signal and is ready to pickup the required safety related loads. To minimize degradation resulting from testing, Diesel Generators may have the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations prior to DG start. | 1

SR 3.8.1.21 and SR 3.8.1.22

These SRs ensure the proper functioning of the safety injection and blackout sequencers.

SR 3.8.1.21 applies to the blackout sequencer input undervoltage relays. These relays are calibrated every 18 months.

SR 3.8.1.22 applies to the Solid State Safeguards Sequencers (both the Safety Injection Sequencer and the Blackout Sequencer) and is the performance of a TADOT. This surveillance is performed every 31 days.

This SR is modified by two Notes. The first Note excludes verification of setpoints from the TADOT. The trip setpoints are verified by as part of the ESF Instrumentation. The second Note excludes actuation of final devices. Operation of the sequencer during power operations could disrupt normal operation and induce a plant transient.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources — Operating," and LCO 3.8.2, "AC Sources — Shutdown."

The starting air system is required to have a minimum capacity for one DG start attempts without recharging the air start receivers.

APPLICABILITY

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

(continued)

BASES (continued)

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period. The amount of fuel oil required during Modes 5 & 6 is less because fewer loads are required to maintain the plant during shutdown conditions.

B.1

With lube oil inventory less than a level one inch below the low run level on the lube oil dipstick, sufficient lubricating oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a level one inch above the bottom of the lube oil dipstick~~,~~. (These levels are for a static condition, i.e., the DG in standby for at least 10 hours - equivalent levels for running conditions may be used and, if used, must be specified in the surveillance procedure for SR 3.8.3.2). 2

(continued)

BASES

ACTIONS

B.1 (continued)

2

NOTE

Subsequent assessments by TXU Electric have concluded that "one inch below the low run level on the lube oil dipstick" and "one inch above the bottom of the lube oil dipstick" are inadequate TS values and the directions provided in NRC Administrative letter 98-10 have been followed. SMF-1999-001803-00 has been initiated to document these nonconforming conditions. Administrative controls have been established to replace "one inch below the low run level on the lube oil dipstick" with "1.75 inches below the low static level" and to replace "one inch above the bottom of the lube oil dipstick" with "5.5 inches below the low static level." A License Amendment Request (LAR) to amend the TS will be submitted to the NRC in a timely fashion.

This level is above where vortexing occurs. This restriction allows sufficient time to obtain the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity , the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

ACTIONS

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the

(continued)

BASES

ACTIONS

D.1 (continued)

stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

E.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through D, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for approximately 7 days at full load. A small volume in the day tank in excess of the day tank requirements is credited to ensure a full 7 day supply. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure 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 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The 1" below low run level requirement is based on the DG manufacturer consumption values for the run time of the DG. (This level is for a static condition, i.e., the DG in standby for at least 10 hours - an equivalent level for running conditions may be used and, if used, must be specified in the surveillance procedure for this Surveillance Requirement). 2

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

2

NOTE

Subsequent assessments by TXU Electric have concluded that "one inch below the low run level on the lube oil dipstick" is an inadequate TS value and the directions provided in NRC Administrative letter 98-10 have been followed. SMF-1999-001803-00 has been initiated to document this nonconforming condition. Administrative controls have been established to replace "one inch below the low run level on the lube oil dipstick" with "1.75 inches below the low static level." A License Amendment Request (LAR) to amend the TS will be submitted to the NRC in a timely fashion.

Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the DG, when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run time are closely monitored by the unit staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-1981 (Ref. 6);

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

b. Verify in accordance with the tests specified in ASTM D975-1981 (Ref. 6) that the sample has an absolute specific gravity at 60/60°F of ≥ 0.8348 and ≤ 0.8984, or an API gravity ≥ 26° and ≤ 38°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes (alternately, Saybolt viscosity, SUS at 100°F of ≥ 32.6, but ≤ 40.1), and a flash point of ≥ 125°F; and | 7

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-1982 (Ref. 6).

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

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-1981 (Ref. 7) are met for new fuel oil when tested in accordance with ASTM D975-1981 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-1979 (Ref. 6) or ASTM D2622-1982 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-1978, Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. For those designs in which the total stored fuel oil volume is contained in two or more interconnected tanks, each tank must be considered and tested separately.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The receiver design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which one start can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). 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 performance of the Surveillance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.7 (continued)

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 10) and Regulatory Guide 1.129 (Ref. 11), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests, not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test. | 3

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load. This will confirm | 3
the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test will be identical to those | 3
specified for a service test and the test discharge rate will envelope the duty cycle of the service test if the modified performance discharge test is performed in lieu of a service test.

The SR is modified by Note 2. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded. This note does not prohibit the application of LCO 3.0.5 or the performance of this SR to restore equipment operability.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1974.
4. FSAR, Chapter 8.
5. IEEE-485-1978.
6. FSAR, Chapter 6.
7. FSAR, Chapter 15.
8. Regulatory Guide 1.93, December 1974.
9. IEEE-450-1995. | 7
10. Regulatory Guide 1.32, February 1977.
11. Regulatory Guide 1.129, February 1978.

Table B 3.8.4-1
DC SOURCES (Page 1 of 1)

TRAIN A		TRAIN B	
125 V DC Bus 1ED1(2ED1) Energized From Battery BT1ED1(BT2ED1) and Battery Charger BC1ED1-1 (BC2ED1-1) or BC1ED1-2 (BC2ED1-2)	125 V DC Bus 1ED3(2ED3) Energized From Battery BT1ED3(BT2ED3) and Battery Charger BC1ED3-1 (BC2ED3-1) or BC1ED3-2 (BC2ED3-2)	125 V DC Bus 1ED2(2ED2) Energized From Battery BT1ED2(BT2ED2) and Battery Charger BC1ED2-1 (BC2ED2-1) or BC1ED2-2 (BC2ED2-2)	125 V DC Bus 1ED4(2ED4) Energized From Battery BT1ED4(BT2ED4) and Battery Charger BC1ED4-1 (BC2ED4-1) or BC1ED4-2 (BC2ED4-2)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for satisfying Category A and Category C specific gravity limits.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. IEEE-450-1995. | 7

BASES (continued)

APPLICABILITY

The inverters 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.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters — Shutdown."

ACTIONS

A.1

With a required inverter inoperable, its associated AC vital bus becomes inoperable until it is re-energized by an operable inverter or the alternate bypass power supply from the Class 1E transformers. | 7

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems — Operating." This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from its Class 1E transformer, it is relying upon non-regulating interruptible AC electrical power sources (offsite and onsite). Because of the potential impact of interrupted power on the Emergency Diesel Generator and the Solid State Safeguards Blackout Sequencer during a postulated Loss of Offsite Power event, these components are considered inoperable when operating on inverter bypass power, and evaluated under the SFDP of Specification 5.5.15. The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices. | 7

(continued)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems — Operating

BASES

BACKGROUND

The onsite Class 1E AC, DC, and AC vital bus electrical power distribution systems are divided by train into two redundant and independent AC, DC, and AC vital bus electrical power distribution subsystems.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 6.9 kV bus and secondary load centers and 480 and 120 V buses. Each 6.9 kV ESF bus has two separate and independent offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 6.9 kV ESF bus is normally connected to a preferred offsite source. After a loss of the preferred offsite power source to a 6.9 kV ESF bus, a slow transfer to the alternate offsite source is accomplished. If the alternate offsite sources are unavailable, the onsite emergency DG supplies power to the 6.9 kV ESF bus. Control power for the 6.9 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources — Operating," and the Bases for LCO 3.8.4, "DC Sources — Operating."

The secondary AC electrical power distribution system for each train includes the safety related load centers shown in Table B 3.8.9-1.

The 118 VAC vital buses are arranged in two load groups per train and are normally powered from the inverters. The alternate power supply for the vital buses are Class 1E transformers powered from the same train as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters — Operating." | 7

There are two independent 125 VDC electrical power distribution subsystems (one for each train).

The list of all required distribution buses is presented in Table B 3.8.9-1.

(continued)

BASES

LCO (continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, and load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via inverted DC voltage or the alternate bypass power supply via Class 1E transformers. | 7

APPLICABILITY

The electrical power distribution subsystems 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.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 8 hours.

(continued)

BASES

ACTIONS (continued)

A.4

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution paths. Secured closed includes a mechanical stop for the manual isolation valve CS-8455 or mechanical stops for the manual isolation valves CS-8439, CS-8441, CS-8460, and CS-8453 and removal of air or electrical power | 7
from the fail-closed, air operated valve FCV-111B. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that all unborated water sources are isolated, precluding a dilution. The boron concentration is checked every 72 hours during MODE 6 under SR 3.9.1.1. This Surveillance demonstrates that the valves are closed through a system walkdown (which may include the use of local or remote indicators). The 31 day Frequency is based on engineering judgment and is considered reasonable in view of other administrative controls that will ensure that the valve opening is an unlikely possibility.

REFERENCES

1. FSAR, Section 15.

2. NUREG-0800, Section 15.4.6.

BASES

BACKGROUND (continued)

doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; however, both personnel air lock doors may be open provided that one personnel air lock door is capable of being closed, and one emergency air lock door is closed. | 7

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The containment ventilation isolation system includes three subsystems. The Containment Purge System includes a 48 inch supply penetration and a 48 inch exhaust penetration. The Containment Pressure Relief System includes an 18 inch exhaust penetration. The Hydrogen Purge System includes a 12 inch supply penetration and a 12 inch exhaust penetration. During MODES 1, 2, 3, and 4, the two valves in each of the Containment Purge System and Hydrogen Purge System supply and exhaust penetrations are secured in the closed position. The two valves in the Containment Pressure Relief System penetration can be opened continuously, but are closed automatically by the Engineered Safety Features Actuation System (ESFAS). None of the subsystems are subject to a Specification in MODE 5.

In MODE 6, large air exchangers are necessary to conduct refueling operations. The normal 48 inch Containment Purge System is used for this purpose, and all four valves are closed by the Containment Radiation Monitor in accordance with LCO 3.3.6, "Containment Ventilation Isolation Instrumentation."

The Containment Pressure Relief System remain operational in MODE 6, and both valves are also closed by the Containment Ventilation Isolation Instrumentation.

(continued)

COMANCHE PEAK ELECTRIC STATION UNITS 1 & 2
TECHNICAL SPECIFICATIONS BASES MANUAL

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Revision 2	None	July 29, 1999
Revision 3	A66	August 31, 1999
Revision 4	A67	September 29, 1999
Revision 5	A69, A70 & A71	September 30, 1999
Revision 6	A72	October 7, 1999
Revision 7	None	November 24, 1999
Revision 8	A73	December 30, 1999

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