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102-04444-AKK/SAB/GAM
May 9, 2000

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-37
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, and 3
Docket Nos. STN 50-528/529/530
Technical Specifications Bases Revision 2 Update

Pursuant to PVNGS Technical Specification (TS) 5.5.14, "Technical Specifications Bases Control Program," Arizona Public Service Company (APS) is submitting the changes to the TS Bases that have been implemented between July 1999 and May 2000. These changes are provided in the enclosure on Revision 2 pages with the changes identified by revision bars. Also enclosed are insertion instructions for the Revision 2 pages.

No commitments are being made to the NRC by this letter.

Should you have any questions, please contact Scott A. Bauer at (623) 393-5978.

Sincerely,

Angela K Krainik

AKK/SAB/GAM/kg

Enclosures

cc: E. W. Merschoff (all w/o enclosure)
M. B. Fields
J. H. Moorman

A001

PVNGS Technical Specifications Bases Revision 2

Insertion Instructions

PVNGS Technical Specifications Bases Revision 2 Insertion Instructions

Remove Page:	Insert New Page:
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PVNGS Technical Specifications Bases Revision 2

Revised Bases Pages

PVNGS

Palo Verde Nuclear Generating Station
Units 1, 2, and 3

Technical Specification Bases

Revision 2
May 12, 2000

PALO VERDE

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B 3.3 INSTRUMENTATION

B 3.3.7 Diesel Generator (DG) - Loss of Voltage Start (LOVS)

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or insufficiently stable to allow safe unit operation. Undervoltage protection will generate a LOVS in the event a Loss of Voltage (LOV) or Degraded Voltage (DV) condition occurs.

Four solid-state relays and four induction disk relays are provided on each 4.16 kV Class 1E bus for the purpose of detecting a sustained degraded voltage or a loss of bus voltage condition, respectively. The protective function of the Degraded Voltage Relays is maintained by assuring that they always actuate when voltage is ≤3697 V. To prevent spurious actuations, the Degraded Voltage Relays will not actuate when voltage is >3786 V. The time delay for the Degraded Voltage Relays is a maximum of 35 seconds and is not affected by the voltage level at which they are actuated. The Loss of Voltage Relays actuate at a lower voltage. Their time delay varies depending on the voltage level, the lower the voltage, the shorter the time delay. The primary function of the Loss of Voltage Relays is to trip in 2.4 seconds or less for a complete loss of voltage condition. The Balance of Plant Engineered Safety Features Activation System (BOP ESFAS) Loss of Power/Load Shed (LOP/LS) module receives inputs from the LOV and DV relays. The LOP/LS module has four channels, each of the channels has one LOV input and one DV input. If either a LOV or DV signal is received in that channel, the channel trips. If any 2 of the 4 channels trip, a signal is sent to the BOP ESFAS Diesel Generator Start Signal (DGSS) module starting the diesel. The LOVS initiated actions are described in "Onsite Power Systems" (Ref. 1).

Trip Setpoints and Allowable Values

Based on the trip setpoint, Calculation 13-EC-PB-202 (Ref. 5) establishes allowable minimum dropout and maximum reset values for the Degraded Voltage Relays, taking into account calibration tolerances, instrumentation uncertainties, and instrument drift. Maintaining the minimum dropout voltage (≥3697 V and ≤3786 V) ensures protection during sustained degraded voltage conditions.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Maintaining the maximum reset voltage (approximately 3805 V, Ref. 6) prevents spurious actuation during analyzed conditions. Calculations 01, 02, 03-EC-MA-221 (Ref. 6) verify that the voltage will recover above the maximum reset value following the most adverse accident loading scenario, and that the relays will not actuate during the transient period of automatic load sequencing.

Setpoints in accordance with the Allowable Values will ensure that the consequences of accidents will be acceptable, providing the plant is operated from within the LCOs at the onset of the accident and the equipment functions as designed.

The undervoltage protection scheme has been designed to protect the plant from spurious trips caused by the offsite power source. A complete loss of offsite power will result in approximately a 2 second delay in LOVS actuation. The DG starts and is available to accept loads within a 10 second time interval on the Engineered Safety Features Actuation System (ESFAS) or LOVS. Emergency power is established within the maximum time delay assumed for each event analyzed in the accident analysis (Ref. 2).

Since there are four protective channels in a two-out-of-four trip logic for each division of the 4.16 kV power supply, no single sensor failure will cause or prevent protective system actuation.

APPLICABLE SAFETY ANALYSES

The DG – LOVS is required for Engineered Safety Features (ESF) systems to function in any accident with a loss of offsite power. Its design basis is that of the ESFAS.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.2 (continued)

The as found and as left values must also be recorded and reviewed for consistency.

SR 3.3.7.3

SR 3.3.7.3 is the performance of a CHANNEL CALIBRATION every 18 months. The CHANNEL CALIBRATION verifies the accuracy of each component within the instrument channel. This includes calibration of the Loss of Voltage and Degraded Voltage relays and demonstrates that the equipment falls within the specified operating characteristics defined by the manufacturer. The Surveillance verifies that the channel responds to a measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drift between successive surveillances to ensure the instrument channel remains operational. CHANNEL CALIBRATIONS must be performed consistent with the plant specific setpoint analysis. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint analysis.

The as found and as left values must also be recorded and reviewed for consistency.

The setpoints, as well as the response to a Loss of Voltage and Degraded Voltage test, shall include a single point verification that the trip occurs within the required delay time, as shown in Reference 1. The Frequency is based upon the assumption of an 18 month calibration interval for the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 8.3
2. UFSAR, Chapter 15.
3. Controlled Dwg. Relay Setpoint Sheets.
4. 10 CFR 50, Appendix A, GDC 21.
5. Calculation 13-EC-PB-202
6. Calculations 01, 02, 03-EC-MA-221

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B 3.3 INSTRUMENTATION

B 3.3.9 Control Room Essential Filtration Actuation Signal (CREFAS)

BASES

BACKGROUND

This LCO encompasses CREFAS actuation, which is an instrumentation channel that performs an actuation Function required for plant protection but is not otherwise included in LCO 3.3.6, "Engineered Safety Features Actuation System (ESFAS) Logic and Manual Trip," or LCO 3.3.7, "Diesel Generator (DG) – Loss of Voltage Start (LOVS)." This is a BOP ESFAS Function that, because of differences in purpose, design, and operating requirements, is not included in LCO 3.3.6 and LCO 3.3.7.

The CREFAS initiates actuation of the Control Room Essential Filtration System to minimize operator radiation exposure. The CREFAS includes two independent, redundant subsystems, including actuation trains. Each train has a gaseous activity radiation monitor for the control room air intake activity. If either train radiation monitor indicates an unsafe condition, both CREFAS trains will be actuated (one-out-of-two logic). The two trains actuate separate equipment. Actuating either train will perform the intended function. A CREFAS is also initiated by a Containment Purge Isolation Actuation Signal (CPIAS) from either of the two CPIAS channels or by a Fuel Building Essential Ventilation Actuation Signal (FBEVAS) from either of the two FBEVAS channels. Control room filtration also occurs on a Safety Injection Actuation Signal (SIAS).

Trip Setpoints and Allowable Values

Trip setpoints used in the bistables are based on the analytical limits (Ref. 1). The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. The trip setpoints are digitally generated by the radiation monitors. These trip values are not subject to drifts common to analog type equipment. The allowable value for this trip is therefore the same as the trip setpoint.

(continued)

BASES (continued)

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Setpoints in accordance with the Allowable Value will ensure that the consequences of Design Basis Accidents will be acceptable, providing the plant is operated from within the LCOs at the onset of the AOO or accident and the equipment functions as designed.

APPLICABLE SAFETY ANALYSES

The CREFAS maintains the control room atmosphere within conditions suitable for prolonged occupancy throughout the duration of any one of the accidents discussed in Reference 1. The radiation exposure of control room personnel, through the duration of any one of the postulated accidents discussed in "Accident Analysis," FSAR, Chapter 15 (Ref. 1), does not exceed the limits set by 10 CFR 50, Appendix A, GDC 19 (Ref. 2).

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

LCO

LCO 3.3.9 requires one channel of CREFAS to be OPERABLE. The required channel consists of Actuation Logic, Manual Trip, and a gaseous radiation monitor. The Actuation Logic includes a cross-train trip function, which ensures that both CREFS units are actuated from a single, operable CREFAS channel. The specific trip setpoint for the CREFAS is listed in the SR.

Each trip setpoint specified is more conservative than the analytical limit assumed in the transient and accident analysis in order to account for instrument uncertainties appropriate to the trip Function. A channel is inoperable if its actual trip setpoint is not set to the value specified in SR 3.3.9.2.

The Bases for the LCO on the CREFAS are discussed below for each Function:

(continued)

BASES

LCO (continued)

12. Steam Generator Water Level

Steam Generator Water Level is provided to monitor operation of decay heat removal via the steam generators. The Category I indication of steam generator level is the wide range level instrumentation. The wide range level covers a span of 143 inches above the lower tubesheet to 55.5 inches above the steam separator deck.

Wide Range Steam Generator Level is a Type A variable because the operator must manually control steam generator level during a Steam Generator Tube Rupture (STGR) event to ensure steam generator tube coverage. At PVNGS wide range Steam Generator Level Instrumentation consists of:

SGA-LT-1113A
SGB-LT-1113B
SGC-LT-1113C
SGD-LT-1113D

SGA-LT-1123A
SGB-LT-1123B
SGC-LT-1123C
SGD-LT-1123D

13. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for AFW. The CST provides the ensured, safety grade water supply for the AFW System. Inventory is monitored by a 3 ft. to 50 ft. level indication. CST Level is displayed on a control room indicator.

At PVNGS CST Level Instrumentation consists of:

CTA-LT-35
CTB-LT-36

(continued)

BASES

LCO
(continued)

14, 15, 16, 17. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

An evaluation was made of the minimum number of valid core exit thermocouples necessary for inadequate core cooling detection. The evaluation determined the reduced complement of core exit thermocouples necessary to detect initial core recovery and trend the ensuing core heatup. The evaluations account for core nonuniformities including incore effects of the radial decay power distribution and excore effects of condensate runback in the hot legs and nonuniform inlet temperatures.

Based on these evaluations, adequate or inadequate core cooling detection is ensured with two valid core exit thermocouples per quadrant.

The design of the Incore Instrumentation System includes a Type K (chromel alumel) thermocouple within each of the 61 incore instrument detector assemblies.

The junction of each thermocouple is located a few inches above the fuel assembly, inside a structure that supports and shields the incore instrument detector assembly string from flow forces in the outlet plenum region. These core exit thermocouples monitor the temperature of the reactor coolant as it exits the fuel assemblies.

The core exit thermocouples have a usable temperature range from 32°F to 2300°F, although accuracy is reduced at temperatures above 1800°F.

(continued)

B 3.3 INSTRUMENTATION

B 3.3.11 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator safety valves or the steam generator atmospheric dump valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allow extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish control at the remote shutdown panel and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located at the remote shutdown panel. Some controls and transfer switches will be operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the Remote Shutdown System control and instrumentation Functions ensures that there is sufficient information available on selected plant parameters to bring the plant to, and maintain it in, MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down the plant and maintain it in a safe condition in MODE 3.

The criteria governing the design and the specific system requirements of the Remote Shutdown System are located in

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

10 CFR 50, Appendix A, GDC 19 (Ref. 1) and Appendix R (Ref. 2).

The Remote Shutdown System has been identified as an important contributor to the reduction of plant accident risk and, therefore, has been retained in the Technical Specifications, as indicated in 10 CFR 50.36 (c)(2)(ii).

LCO

The Remote Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room. The instrumentation required is listed in Table 3.3.11-1 in the accompanying LCO. The disconnect switches and control circuits are listed in PVNGS controlled documents.

The controls, instrumentation, and transfer switches are those required for:

- Reactivity Control (initial and long term);
- RCS Pressure Control;
- Decay Heat Removal;
- RCS Inventory Control; and
- Safety support systems for the above Functions, as well as the essential spray pond system, essential cooling water system, and onsite power including the diesel generators.

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the remote shutdown Functions are OPERABLE. That is, they are able to place the plant in a safe shutdown condition from a location other than the control room. The intent of this Technical Specification is to provide the requirements for the OPERABILITY of the instrumentation and controls necessary to place the plant in safe shutdown from a location other than the control room, not to govern safe shutdown component OPERABILITY or allowed out of service times.

(continued)

BASES

LCO (continued)

The Remote Shutdown System instrumentation and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure that the instrument and control circuits will be OPERABLE if plant conditions require that the Remote Shutdown System be placed in operation.

The allowed out of service time is controlled via the applicable system LCOs or administrative controls established by approved plant procedures. For the purpose of this specification, equipment that is disabled in its safe shutdown condition is considered OPERABLE, however, Technical Specifications need to be reviewed for the applicable system LCO impacts on disabled equipment. Therefore, LCO 3.3.11 only needs to be entered when the instrumentation and/or control circuit is actually disabled or inoperable such that it can't be used from the RSP or controlled locally.

If a control circuit is impacted for the performance of a surveillance test, LCO 3.3.11 need not be entered as long as restoration can reasonably be done within the time frame required to meet Shutdown Cooling entry conditions. However, if a clearance is hung for the performance of maintenance on the equipment/control circuit, then the equipment/control circuit is considered inoperable and LCO 3.3.11 needs to be entered. Additionally, the appropriate system LCO/TLCO also needs to be evaluated to determine if entry is required based on current plant conditions.

Refer to the following examples: (NOTE: Entry into the appropriate system LCO/TLCO also needs to be evaluated to determine if entry is required based on current plant conditions.)

- Charging pump CHBP01 has been isolated for pulsation dampener checks. Entry into 3.3.11 is NOT required because the control circuitry for CHBP01 remains operable.

- Charging pump CHBP01 has been declared inoperable because the pump will not respond to the controls located on the switchgear. Entry into 3.3.11 IS required because the control circuitry for CHBP01 does not function properly.

(continued)

BASES

LCO (continued)

- Atmospheric Dump valve SGBHV185 has been isolated via its block valve to snoop for air leakage. Entry into 3.3.11 is NOT required because the control circuitry for SGBHV185 remains operable.

- Auxiliary Feedwater pump AFBP01 has been removed from service for maintenance. The supply breaker has been racked out and the control power fuses rolled to off. Entry into 3.3.11 IS required because the control circuitry for AFBP01 has been disabled.

- "B" Class pressurizer back-up heaters are de-energized for the performance of 36ST-9SA02. Entry into 3.3.11 is NOT required because the control circuitry for the "B" Class heaters remains operable.

- "B" and "D" PK battery chargers are in service. The "BD" swing charger is tagged out for maintenance. Entry into 3.3.11 IS required because the control circuitry for PKB-H16 has been disabled.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the unit is already subcritical and in the condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control become unavailable.

ACTIONS

A Note has been included that excludes the MODE change restrictions of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS, even though the ACTIONS may eventually require a plant shutdown. This is acceptable due to the low probability of an event requiring this system.

(continued)

BASES

ACTIONS (continued)

A Remote Shutdown System division is inoperable when each Function listed in Table 3.3.11-1 is not accomplished by the required number of channels in Table 3.3.11-1 that satisfies the OPERABILITY criteria for the channel's Function. These criteria are outlined in the LCO section of the Bases.

Note 2 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.11-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be racked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more instrumentation channels of the Remote Shutdown System are inoperable. This includes any Function listed in Table 3.3.11-1.

The Required Action is to restore the channels to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

Condition B addresses the situation where one or more disconnect or control circuits of the Remote Shutdown System are inoperable. The required disconnect and control circuits are listed in PVNGS controlled documents.

The required Action is to restore the required switch(s)/circuit(s) to OPERABLE status or issue procedure changes that identify alternate disconnect methods or control circuits. The Completion Time for either of the two Actions is 30 days.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.3.11.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the plant staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

If the channels are normally off scale during times when surveillance is required, the CHANNEL CHECK will only verify that they are offscale in the same direction. Current loop channels are verified to be reading at the bottom of the range and not failed downscale.

The Frequency of 31 days is based on plant operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.11.2

SR 3.3.11.2 verifies that each required Remote Shutdown System transfer switch and control circuit performs its intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be brought to and maintained in MODE 3 from the remote shutdown panel and the local control stations. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience demonstrates that Remote Shutdown System control channels seldom fail to pass the Surveillance when performed at a Frequency of once every 18 months.

SR 3.3.11.3

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

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

2. 10 CFR 50, Appendix R.

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BASES

APPLICABLE SAFETY ANALYSES (continued)

Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

The RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer.

These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

(continued)

BASES

LCO (continued)

c. The existences, sizes, and orientations of flaws in the vessel material.

The limit curves (Figures 3.4.3-1, 3.4.3-2, 3.4.3-3, and 3.4.3-4) and the tabulated limits (Table 3.4.3-1) on the rate of change of temperature do not account for all instrument uncertainty. Indicated temperature limits 3°F greater and indicated pressure limits approximately 9 psi less than the corresponding LCO limits include appropriate instrument uncertainty and ensure that the pressure, temperature and rate of temperature change of the limiting RCS components are within the actual limits that provide the required margin to brittle failure. These values, which include appropriate instrument uncertainty, are established within the applicable plant procedures.

APPLICABILITY

The RCS P/T limits Specification provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times, except when reactor vessel head is fully detensioned such that the RCS cannot be pressurized, in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

The actions of this LCO consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures.

(continued)

BASES

ACTIONS

A.1 and A.2

Operation outside the P/T limits must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation to within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 5), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

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

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because:

a. The RCS remained in an unacceptable P/T region for an extended period of increased stress; or

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

b. A sufficiently severe event caused entry into an unacceptable region.

Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

Pressure and temperature are reduced by placing the plant in MODE 3 within 6 hours and in MODE 5 with RCS pressure < 500 psia within 36 hours.

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

C.1 and C.2

The actions of this LCO, anytime other than in MODE 1, 2, 3, or 4, consider the premise that a violation of the limits occurred during normal plant maneuvering. Severe violations caused by abnormal transients, at times accompanied by equipment failures, may also require additional actions from emergency operating procedures. Operation outside the P/T limits must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The Completion Time of "immediately" reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in a short period of time in a controlled manner.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Besides restoring operation to within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 5), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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

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

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

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

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, July 1982.
4. 10 CFR 50, Appendix H.
5. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
6. PVNGS Calculation 13-N001-6.02-650-2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops – MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat to the Steam Generators (SGs) or Shutdown Cooling (SDC) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

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

APPLICABLE SAFETY ANALYSES

In MODE 4 , RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS loops and SDC trains provide this circulation.

RCS Loops – MODE 4 have been identified in 10 CFR 50.36 (c)(2)(ii) as important contributors to risk reduction.

LCO

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

(continued)

BASES

LCO (continued)

Note 1 permits all RCPs and SDC pumps to be de-energized ≤ 1 hour per 8 hour period. This means that natural circulation should be established, after the operating RCP or SDC pump is secured, using the SGs. Depending on decay heat and current RCS temperature, it may be difficult to establish verifiable natural circulation. The Note prohibits boron dilution when forced flow is stopped because an even concentration distribution cannot be ensured. The intent is to stop any known or direct positive reactivity additions to the RCS due to dilution. Core outlet temperature is to be maintained at least 10°F below saturation temperature so that no vapor bubble may form and possibly cause a natural circulation flow obstruction. The response of the RCS without the RCPs or SDC pumps depends on the core decay heat load and the length of time that the pumps are stopped. As decay heat diminishes, the effects on RCS temperature and pressure diminish. Without cooling by forced flow, higher heat loads will cause the reactor coolant temperature and pressure to increase at a rate proportional to the decay heat load. Because pressure can increase, the applicable system pressure limits (Pressure and Temperature (P/T) limits or Low Temperature Overpressure Protection (LTOP) limits) must be observed and forced SDC flow or heat removal via the SGs must be re-established prior to reaching the pressure limit. The circumstances for stopping both RCPs or SDC pumps are to be limited to situations where:

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

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

Note 2 requires, that before an RCP may be started with any RCS cold leg temperature ≤ 214°F during cooldown, or ≤ 291°F during heatup, that secondary side water temperature (saturation temperature corresponding to SG pressure) in each SG is < 100°F above each of the RCS cold leg temperatures. The numerical values for RCS cold leg temperature at which this Note is applicable do not account for all instrument uncertainty. Use of an indicated value of 217°F or below during cooldown and 294°F or below during

(continued)

BASES

LCO (continued)

heatup ensures that the actual limits will not be exceeded. These values, which include appropriate instrument uncertainty, are established within the applicable plant procedures.

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

Note 3 restricts RCP operation to no more than 2 RCPs with RCS cold leg temperature ≤ 200°F, and no more than 3 RCPs with RCS cold leg temperature >200°F but ≤ 500°F. Satisfying these conditions will maintain the analysis assumptions of the flow induced pressure correction factors due to RCP operation (Ref. 1)

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

Similarly, for the SDC System, an OPERABLE SDC train is composed of an OPERABLE SDC pump (CS or LPSI) capable of providing flow to the SDC heat exchanger for heat removal. RCPs and SDC pumps are OPERABLE if they are capable of being powered and are able to provide flow, if required.

APPLICABILITY

In MODE 4, this LCO applies because it is possible to remove core decay heat and to provide proper boron mixing with either the RCS loops and SGs or the SDC System.

Operation in other MODES is covered by:

LCO 3.4.4 "RCS Loops-MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation – Low Water Level" (MODE 6).

(continued)

BASES

ACTIONS

A.1

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

B.1

If only one required SDC train is OPERABLE and in operation, redundancy for heat removal is lost. The plant must be placed in MODE 5 within the next 24 hours. Placing the plant in MODE 5 is a conservative action with regard to decay heat removal. With only one SDC train OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining SDC train, it would be safer to initiate that loss from MODE 5 (≤ 210°F) rather than MODE 4 (210°F to 350°F). The Completion Time of 24 hours is reasonable, based on operating experience, to reach MODE 5 from MODE 4, with only one SDC train operating, in an orderly manner and without challenging plant systems.

C.1 and C.2

If no RCS loops or SDC trains are OPERABLE, or in operation, all operations involving reduction of RCS boron concentration must be suspended and action to restore one RCS loop or SDC train to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of decay heat removal. The action to restore must continue until one loop or train is restored to operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one required loop or train is in operation and circulating reactor coolant at a flow rate of greater than or equal to 4000 gpm. This ensures forced flow is providing heat removal. Verification includes flow rate, temperature, or pump status monitoring. The 12 hour Frequency has been shown by operating practice to be sufficient to regularly assess RCS loop status. In addition, control room indication and alarms will normally indicate loop status.

SR 3.4.6.2

This SR requires verification every 12 hours of secondary side water level in the required SG(s) ≥ 25% wide range. An adequate SG water level is required in order to have a heat sink for removal of the core decay heat from the reactor coolant. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess degradation and verify operation within safety analyses assumptions.

SR 3.4.6.3

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

REFERENCES

1. PVNGS Operating License Amendments 52, 38 and 24 for Units 1, 2 and 3, respectively, and associated NRC Safety Evaluation dated July 25, 1990.

2. PVNGS Calculation 13-N001-6.02-652-2.

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BASES

LCO (continued)

In MODE 5, it is sometimes necessary to stop all RCP or SDC forced circulation. This is permitted to change operation from one SDC train to the other, perform surveillance or startup testing, perform the transition to and from the SDC, or to avoid operation below the RCP minimum net positive suction head limit. The time period is acceptable because natural circulation is acceptable for decay heat removal the reactor coolant temperature can be maintained subcooled, and boron stratification affecting reactivity control is not expected.

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

Note 3 requires that before an RCP may be started with any RCS cold leg temperature ≤ 214°F during a cooldown, or ≤ 291°F during a heatup, the secondary side water temperature (saturation temperature corresponding to SG pressure) in each SG must be < 100°F above each of the RCS cold leg temperatures. The numerical values for RCS cold leg temperature at which this Note is applicable do not account for all instrument uncertainty. Use of an indicated value of 217°F or below during cooldown and 294°F or below during heatup ensures that the actual limits will not be exceeded. These values, which include appropriate instrument uncertainty, are established within the applicable plant procedures.

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

Note 4 restricts RCP operation to no more than 2 RCPs with RCS cold leg temperature ≤ 200°F, and no more than 3 RCPs with RCS cold leg temperature > 200°F but ≤ 500°F. Satisfying these conditions will maintain the analysis assumptions of the flow induced pressure correction factors due to RCP operation (Ref. 3).

(continued)

BASES

LCO (continued)

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

An OPERABLE SDC train is composed of an OPERABLE SDC pump (CS or LPSI) capable of providing flow to the SDC heat exchanger for heat removal.

SDC pumps are OPERABLE if they are capable of being powered and are able to provide flow (current Section XI), if required. An OPERABLE SG can perform as a heat sink when it is OPERABLE in accordance with the SG Tube Surveillance Program and has the minimum water level specified in SR 3.4.7.2.

The RCS loops may not be considered filled until two conditions needed for operation of the steam generators are met. First, the RCS must be intact. This means that all removable portions of the primary pressure boundary (e.g., manways, safety valves) are securely fastened. Nozzle dams are removed. All manual drain and vent valves are closed, and any open system penetrations (e.g., letdown, reactor head vents) are capable of remote closure from the control room. An intact primary allows the system to be pressurized as needed to achieve the subcooling margin necessary to establish natural circulation cooling. When the RCS is not intact as described, a loss of SDC flow results in blowdown of coolant through boundary openings that also could prevent adequate natural circulation between the core and steam generators. Secondly, the concentration of dissolved or otherwise entrained gases in the coolant must be limited or other controls established so that gases coming out of solution in the SG U-tubes will not adversely affect natural circulation. With these conditions met, the SGs are a functional method of RCS heat removal upon loss of the operating SDC train. The ability to feed and steam SGs at all times is not required when RCS temperature is less than 210°F because significant loss of SG inventory through boiling will not occur during time anticipated to take corrective action. The required SG level provides sufficient time to either restore the SDC train or implement a method for feeding and steaming the SGs (using non-class components if necessary).

(continued)

BASES (continued)

REFERENCES

1. Not Used

2. CEN-PSD-770 Analysis for Lower Mode Functional Recovery Guidelines.

3. PVNGS Operating License Amendmants 52, 38, and 24 for Units 1, 2 and 3, respectively, and associated NRC Safety Evaluation dated July 25, 1990.

4. PVNGS Calculation 13-N001-6.02-252-2.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Safety Valves-MODE 4

BASES

BACKGROUND

The purpose of the four spring loaded pressurizer safety valves is to provide RCS overpressure protection. One safety valve is used for portions of MODE 4. For the remainder of MODE 4, MODE 5, and MODE 6 with the head on, overpressure protection is provided by operating procedures and the LCO 3.4.13, "Low Temperature Overpressure Protection (LTOP) System."

The self actuated pressurizer safety valves are designed in accordance with the requirements set forth in the ASME, Boiler and Pressure Vessel Code, Section III (Ref. 1). The required lift pressure is 2475 psia +3%, -1%. The safety valves discharge steam from the pressurizer to a quench tank located in the containment. The discharge flow is indicated by an increase in temperature downstream of the safety valves and by an increase in the quench tank temperature and level.

The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

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

(continued)

BASES

BACKGROUND (continued)

Pressurizer Safety Valve Requirements

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit (SL) of 2750 psia. Each safety valve is designed to relieve a minimum of 454,336 lb per hour of saturated steam at valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown above LTOP System temperatures.

Shutdown Cooling System Suction Line Relief Valve Requirements

A single Shutdown Cooling System suction line relief valve provides overpressure relief capability and will prevent RCS overpressurization in the event that no pressurizer safety valves are OPERABLE.

APPLICABLE SAFETY ANALYSES

All accident analyses in the UFSAR that require safety valve actuation assume operation of four pressurizer safety valves to limit increasing reactor coolant pressure. The overpressure protection analysis is also based on operation of four safety valves and assumes that the valves open at the high range of the setting (2475 psia + 3%). These valves must accommodate pressurizer insurges that could occur during a startup, rod withdrawal, ejected rod, loss of main feedwater, or main feedwater line break accident. The Loss of Load with Delayed Reactor Trip accident establishes the minimum safety valve capacity. The Loss of Load with Delayed Reactor Trip accident is assumed to occur at 100% power. Single failure of a safety valve is neither assumed in the accident analysis nor required to be addressed by the ASME Code. Compliance with this specification is required to ensure that the accident analysis and design basis calculations remain valid.

The pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

(continued)

LCO (continued)

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

The Note requires that, before an RCP may be started, the secondary side water temperature (saturation temperature corresponding to SG pressure) in each SG is ≤ 100°F above each of the RCS cold leg temperatures. Satisfying this condition will preclude a large pressure surge in the RCS when the RCP is started.

APPLICABILITY

This LCO is applicable in MODE 4 when the temperature of any RCS cold leg is ≤ 214°F during cooldown or ≤ 291°F during heatup, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 214°F during cooldown and 291°F during heatup. The requirements for overpressure protection in MODES 1, 2 and 3, and in MODE 4 above the LTOP System temperatures are covered by LCO 3.4.10, "Pressurizer Safety Valves - MODES 1, 2, and 3," and LCO 3.4.11, "Pressurizer Safety Valves - MODE 4." When the reactor vessel head is off overpressurization cannot occur.

The numerical values for RCS cold leg temperature at which this is applicable do not account for all instrument uncertainty. Use of an indicated value of 217°F or below during cooldown and 294°F or below during heatup ensures that the actual limits will not be exceeded. These values, which include the appropriate instrument uncertainty, are established in the appropriate plant procedures.

LCO 3.4.3 provides the operational P/T limits for all MODES.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by a Note stating when one or more cold legs reach 214°F, this LCO remains applicable during periods of steady state temperature conditions until all RCS cold leg temperatures reach 291°F. Also, if a cooldown is terminated prior to reaching 214°F and a heatup is commenced, this LCO is applicable until all RCS cold leg

(continued)

APPLICABILITY (continued)

temperatures reach 291°F. This Note provides clarification about Applicability intent. Since PVNGS uses two different temperatures at which the Shutdown Cooling System suction line relief valves must be placed in service there is some possibility of confusion. This Note clarifies those circumstances where the Shutdown Cooling System suction line relief valves must be placed in service.

ACTIONS

A.1

The Required Action is modified by a Note stating that LCO 3.0.4 is not applicable.

In MODE 4 when any RCS cold leg temperature is ≤ 214°F during cooldown or ≤ 291°F during heatup with one Shutdown Cooling System suction line relief valve inoperable, two Shutdown Cooling System suction line relief valves must be restored to OPERABLE status within a Completion Time of 7 days. Two valves are required to meet the LCO requirement and to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time is based on the facts that only one Shutdown Cooling System suction line relief valve is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

B.1

The consequences of operational events that will overpressure the RCS are more severe at lower temperature (Ref. 6). Thus, one required Shutdown Cooling System suction line relief valve inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore inoperable valve to OPERABLE status is 24 hours.

The 24 hour Completion Time to restore two Shutdown Cooling System suction line relief valves OPERABLE in MODE 5 or in MODE 6 when the vessel head is on is a reasonable amount of time to investigate and repair several types of Shutdown Cooling System suction line relief valve failures without exposure to a lengthy period with only one Shutdown Cooling System suction line relief valve OPERABLE to protect against overpressure events.

(continued)

ACTIONS (continued)

C.1

If two required Shutdown Cooling System suction line relief valves are inoperable, or if a Required Action and the associated Completion Time of Condition A or B are not met, the RCS must be depressurized and a vent established within 8 hours. The vent must be sized at least 16 square inches to ensure the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action protects the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel. For personnel safety considerations, the RCS cold leg temperature must be reduced to less than 200°F prior to venting.

The Completion Time of 8 hours to depressurize and vent the RCS is based on the time required to place the plant in this condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and 3.4.13.2

SR 3.4.13.1 and SR 3.4.13.2 require verifying that the RCS vent is open ≥ 16 square inches or that the Shutdown Cooling System suction line relief valves be aligned to provide overpressure protection for the RCS is proven OPERABLE by verifying its open pathway condition either:

Shutdown Cooling System suction/line relief valves

a. Once every 12 hours for a valve that is unlocked, not sealed, or otherwise not secured open in the vent pathway, or

b. Once every 31 days for a valve that is locked, sealed, or otherwise secured open in the vent pathway.

RCS Vent

a. Once every 12 hours for a vent pathway that is unlocked, not sealed, or otherwise not secured open

b. Once every 31 days for a vent pathway that is locked, sealed, or otherwise secured open.

For an RCS vent to meet the specified flow capacity, it requires removing all pressurizer safety valves, or similarly establishing a vent by opening the pressurizer manway (Ref. 11). The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 and 3.4.13.2 (continued)

The passive vent arrangement must only be open (vent pathway exists) to be OPERABLE. These Surveillances need only be performed if the vent or the Shutdown Cooling System suction line relief valves are being used to satisfy the requirements of this LCO. The Frequencies consider operating experience with mispositioning of unlocked and locked pathway vent valves, and passive pathway obstructions.

SR 3.4.13.3

SRs are specified in the Inservice Testing Program. Shutdown Cooling System suction line relief valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 10), which provides the activities and the Frequency necessary to satisfy the SRs. The Shutdown Cooling System suction line relief valve set point is 467 psig.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. UFSAR, Section 15.
4. 10 CFR 50.46.
5. 10 CFR 50, Appendix K.
6. Generic Letter 90-06.
7. UFSAR, Section 5.2.
8. V-PSAC-009, Pressure Transient Analysis.
9. V-PSAC-010, Mass Input Pressure Transient in Water Solid RCS.
10. ASME, Boiler and Pressure Vessel Code, Section XI.
11. 13-COO-93-016, Sensitivity Study on Pressurizer Vent Paths vs. Days Post Shutdown.
12. PVNGS Calculation 13-N001-6.02-252-2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Operational LEAKAGE

BASES

BACKGROUND

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

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

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

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

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

This LCO deals with protection of the Reactor Coolant Pressure Boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analysis radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a Loss Of Coolant Accident (LOCA).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes a 1 gpm primary to secondary LEAKAGE as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a Steam Line Break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a Steam Generator Tube Rupture (SGTR). The leakage contaminates the secondary fluid.

The Technical Specification limit of 150 gallons per day (gpd) primary to secondary LEAKAGE through any one steam generator is significantly less than the initial conditions assumed in the safety analyses. The 150 gpd limit is based on operating experience as an indication of one or more propagating tube leak mechanisms. This leakage rate limit provides additional assurance against tube rupture at normal and faulted conditions and provides additional assurance that cracks will not propagate to burst prior to detection by leakage monitoring methods and commencement of plant shutdown.

The UFSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is only briefly released via safety valves and the majority is steamed to the condenser. The 150 gpd allowable primary to secondary LEAKAGE is relatively inconsequential.

The SLB is more limiting for site radiation releases. The safety analysis for the SLB accident assumes 1 gpm primary to secondary LEAKAGE in one generator as an initial condition. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 50 or the staff approved licensing basis (i.e., a small fraction of these limits).

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

(continued)

BASES

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 monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of identified 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.

(continued)

BASES

LCO (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 leaktight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

d. Primary to Secondary LEAKAGE through Any One SG

The maximum allowable operational primary to secondary LEAKAGE through any one SG of 150 gpd is based on operating experience as an indication of one or more propagating tube leak mechanisms. This operational limit is significantly less than the initial conditions assumed in the safety analyses. The Steam Generator Tube Surveillance Program described in TS Section 5.5.9 ensures that the structural integrity of the SG tubes is maintained. The 150 gpd leakage rate limit provides additional assurance against tube rupture at normal and faulted conditions and provides additional assurance that cracks will not propagate to burst prior to detection by leakage monitoring methods and commencement of plant shutdown. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

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

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, identified, 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. The reactor must be brought to MODE 3 within 6 hours and to 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 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.

C.1

If one or more SGs are inoperable, due to SR 3.4.14.2, the unit is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

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. 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 performed with the reactor at steady state operating conditions and near operating pressure. Therefore, this SR is not required to be performed in MODES 3 and 4, until 12 hours of steady state operation near operating pressure have elapsed. This means that once steady state operating conditions are established, 12 hours is allowed for completing the Surveillance if the Surveillance Frequency interval was exceeded in MODE 5 or 6. Further discussion of SR note format is found in Section 1.4, Frequency.

The Note in the Frequency column allows for SR 3.4.14.1 nonperformance due to planned or unplanned power manipulations. This Note is not intended to allow power manipulations solely for the purpose of avoiding SR 3.4.14.1 performance. Steady state operation is required to perform a proper water inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

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. These leakage detection systems are specified in LCO 3.4.16, "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. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.14.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 15.

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B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

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

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

Industry practice has shown that water flow changes of 0.5 gpm to 1.0 gpm can readily be detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump monitor consists of instrumentation used to monitor containment sump level and flow (pump run time). The containment sump used to collect unidentified LEAKAGE is instrumented to alarm if the rate of level increase corresponds to a sump inflow greater than 1 gpm for 1 hour (Ref. 3). This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring and of 10^{-6} μCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate and gaseous activities, because of their sensitivities and responses to RCS LEAKAGE.

(continued)

BASES

BACKGROUND (continued)

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

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

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

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The RCS leakage detection instrumentation is described in the UFSAR (Ref. 3). Multiple instrument locations are utilized, if needed, to help identify the location of the LEAKAGE source.

(continued)

BASES

LCO (continued)

Simultaneous hot and cold leg injection will maintain core cooling and boric acid flushing following a large break LOCA.

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

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure ≥ 1837 psia or with RCS T_c ≥ 485°F the ECCS OPERABILITY requirements for the limiting Design Basis Accident (DBA) large break LOCA are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The HPSI pump performance is based on the small break LOCA, which establishes the pump performance curve and has less dependence on plant power. The minimum T_c is based on the ECCS OPERABILITY requirements for a MODE 3 steam line break with a stuck rod and a single HPSI failure to prevent a return to power. The requirements of MODES 2 and 3, with RCS pressure ≥ 1837 psia or with RCS T_c ≥ 485°F, are bounded by the MODE 1 analysis.

The ECCS functional requirements of MODE 3, with RCS pressure < 1837 psia and with RCS T_c < 485°F, and MODE 4 are described in LCO 3.5.4, "ECCS - Shutdown."

In MODES 5 and 6, unit conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Shutdown Cooling (SDC) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Shutdown Cooling (SDC) and Coolant Circulation - Low Water Level."

(continued)

BASES

ACTIONS

A.1

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

If LCO 3.5.3 requirements are not met due only to the existence of Condition A, then the inoperable LPSI subsystem components must be returned to OPERABLE status within 7 days of discovery of Condition A. This 7 day Completion Time is based on the findings of the deterministic and probabilistic analysis that are discussed in Reference 6. Seven days is a reasonable amount of time to perform many corrective and preventative maintenance items on the affected LPSI subsystem. Reference 6 concluded that the overall risk impact of this Completion Time was either risk-beneficial or risk-neutral.

The Configuration Risk Management Program (CRMP) in TRM Section 5.0.500.19 applies when Condition A is entered.

B.1

If one or more ECCS trains are inoperable, except for reasons other than Condition A (one LPSI subsystem inoperable), and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC study (Ref. 4) using a reliability evaluation and is a reasonable amount of time to effect many repairs.

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

(continued)

BASES

ACTIONS

B.1 (continued)

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

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

With one or more components inoperable, such that 100% of the equivalent flow to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be immediately entered.

C.1, C.2, and C.2

If the inoperable train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and pressurizer pressure reduced to < 1837 psia and RCS Tc reduced to < 485°F within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve automatically repositions within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is appropriate because the valves are operated under procedural control and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.3.2

With the exception of systems in operation, the ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. The method of ensuring that any voids or pockets of gases are removed from the ECCS piping is to vent the accessible discharge piping high points, which is controlled by PVNGS procedures. Maintaining the piping from the ECCS pumps to the RCS full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent water hammer, pump cavitation, and pumping of noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SIAS or during SDC. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the adequacy of the procedural controls governing system operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.3

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

SR 3.5.3.4, SR 3.5.3.5, and SR 3.5.3.6

These SRs demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SIAS and on an RAS, that each ECCS pump starts on receipt of an actual or simulated SIAS, and that the LPSI pumps stop on receipt of an actual or simulated RAS. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillances were performed with the reactor at power. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of the Engineered Safety Feature Actuation System (ESFAS) testing, and equipment performance is monitored as part of the Inservice Testing Program.

The following valve actuations must be verified at least once per 18 months:

on an actual or simulated recirculation actuation signal, the containment sump isolation valves open, and the HPSI, LPSI and CS minimum bypass recirculation flow line isolation valves and combined SI mini flow valve close.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.3.7

Realignment of valves in the flow path on an SIAS is necessary for proper ECCS performance. The safety injection valves have stops to position them properly so that flow is restricted to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The 18 month Frequency is based on current industry practice. These valves are also monitored in accordance with the requirements of 10 CFR 50.65 (Ref. 5).

SR 3.5.3.8

Periodic inspection of the containment sump ensures that it is unrestricted and stays in proper operating condition. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during an outage, on the need to have access to the location, and on the potential for unplanned transients if the Surveillance were performed with the reactor at power. This Frequency is sufficient to detect abnormal degradation and is confirmed by operating experience.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.

2. 10 CFR 50.46.

3. UFSAR, Chapter 6.

4. NRC Memorandum to V. Stello, Jr., from R. L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

5. 10 CFR 50.65.

6. Combustion Engineering Owners Group Joint Applications Report for Low Pressure Safety Injection System AOT Extension, CE NPSD-995, dated May 1995, as submitted to NRC in APS letter no. 102-03392, dated June 13, 1995, with updates described in letter no. 102-04250 dated February 26, 1999. Also see TS amendment no. 124 dated February 1, 2000.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

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

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

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

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

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer (NBN-X03 and NBN-X04) supplying offsite power to the onsite Class 1E Distribution System. Within 30 seconds after the initiating signal is received, all permanently connected and auto-connected emergency loads needed to recover the unit or maintain it in a safe condition are returned to service via the automatic load sequencer.

(continued)

BASES

BACKGROUND (continued)

The onsite standby power source for each 4.16 kV ESF bus is dedicated DG. DG-A and DG-B are dedicated to ESF buses PBA-S03 and PBB-S04, respectively. A DG starts automatically (in emergency mode) on a safety injection actuation signal (SIAS) (i.e., low pressurizer pressure or high containment pressure signals), auxiliary feedwater actuation signals (AFAS-1 and AFAS-2) (e.g., low steam generator level), or on a loss of power (an ESF bus degraded voltage or undervoltage signal). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with a SIAS or AFAS signal. Following the loss of offsite power, the sequencer sheds nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application. The DGs will also start and operate in the standby mode (running unloaded) without tying to the ESF bus on a SIAS or AFAS.

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

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 40 seconds after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 5500 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in the updated FSAR, Chapter 8 (Ref. 2).

Offsite power sources must have the capability to effect a safe shutdown and to mitigate the effects of an accident as specified in Regulatory Guide 1.93 (Ref. 6). As a result of

(continued)

BASES

BACKGROUND (continued)

certain anticipated operational occurrences (AOOs) and design basis accidents (DBAs), the voltage to ESF buses PBA-S03 and PBB-S04 would change as a result of one or more of the following three automatic operations: (1) tripping of the generating unit, (2) fast bus transfer of the non-Class 1E distribution system to the startup transformers, and (3) powering of the ESF loads by the automatic load sequencer. Analyses have been performed to determine the magnitude of voltage change due to each of these operations. Under conditions where these voltage changes would result in either inadequate voltages to the ESF equipment or tripping of the degraded voltage relays, the guidance from Regulatory Guide 1.93 (Ref. 6) is not met and the affected offsite circuit(s) do not meet their required capability.

Tripping of a Palo Verde unit can result in either a decrease or increase in the switchyard voltage due to the change in the flow of volt-amperes reactive (VARs) into or out of the electrical grid. The maximum voltage change (following the trip of the only operating unit) has been determined analytically. This analysis bounds the condition of one 525 kV line out of service and no Palo Verde unit on line during the event (assumes unit trip at the beginning of the event). In that case, tripping of the unit results in loss of local switchyard voltage control, and the switchyard voltage has more latitude to change than it would with one or both of the other Palo Verde units remaining on line. When generating power, the Palo Verde units provide automatic regulation of the switchyard voltage.

If an accident results in a loss of local switchyard voltage control (last operating unit loses capability to regulate switchyard voltage) and more than one 525 kV transmission line is out of service, the condition is not bounded by the transmission system studies. Therefore, the post-trip switchyard voltage is indeterminate, and it must be considered that both offsite circuits do not meet their required capability.

Voltage analyses also conclude that the maximum switchyard voltage should not exceed 535.5 kV. However, even if this limit is exceeded, the offsite circuits still have the capability to effect a safe shutdown, mitigate the effects of an accident, and continue to meet the operability

(continued)

BASES

BACKGROUND (continued)

requirements of Regulatory Guide 1.93 (Ref. 6). Although sustained overvoltages can cause accelerated aging of electrical equipment, this would not cause catastrophic equipment failure or unavailability. Furthermore, an overvoltage condition can be corrected quickly by adjustment of the MVAR output of the Palo Verde generator(s). Therefore, there is no LCO for high switchyard voltage.

Grid frequency can also affect the operation of safety equipment. For example, high frequency can result in an excessive differential pressure across motor operated valves, and low frequency can result in substandard pump flow. There are no LCOs for offsite circuit frequency, because the grid frequency is continuously monitored and maintained within a tight tolerance by non-Palo Verde organizations. These organizations utilize various automatic and manual methods to control frequency, such as maintaining a spinning reserve, load shedding, and turbine-governor controls. Analyses, as documented in UFSAR Appendix 8B (Ref. 2), and operating experience have demonstrated that the tripping of a Palo Verde unit has a minimal effect on grid frequency.

APPLICABLE SAFETY ANALYSES

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

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

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

b. A worst case single failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

LCO

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

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

In addition, one automatic load sequencer per train must be OPERABLE.

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

The startup transformers (NAN-X01, NAN-X02, and NAN-X03) convert the 525 kV offsite power to the Non-Class 1E 13.8 kV power. Each secondary winding of a startup transformer normally provides power to one of two interconnected 13.8 kV intermediate buses (NAN-S05 & NAN-S06) per unit, in such a way that the two 13.8 kV intermediate buses of the same unit receive power from two different start-up transformers (preferred offsite sources: normal and alternate supply). For example, Unit 1 NAN-S05's normal supply is from a NAN-X03 secondary winding and NAN-S05's alternate supply is from a NAN-X01 secondary winding; Unit 1 NAN-S06's normal supply is from a NAN-X02 secondary winding and NAN-S05's alternate supply is from a NAN-X01 secondary winding. The secondary winding are sized to start and carry one-half of the non-Class 1E loads of one unit and two trains of ESF loads, one which is from another unit, during unit trips or during startup/shutdown operation.

The 13.8 kV intermediate buses (NAN-S05 & NAN-S06), in turn, distribute power to the 4.16 kV Class 1E buses (PBA-S03 & PBB-S04) via a 13.8 kV bus (NAN-S03 or NAN-S04) and an ESF transformer (NBN-X03 or NBN-X04).

(continued)

BASES

LCO (continued)

Two fast bus transfer circuits are also provided to transfer the non-Class 1E house loads fed from NAN-S01 and NAN-S02 to 13.8 kV buses NAN-S03 and NAN-S04 respectively during a plant trip or during startup/shutdown operation. Prior to a plant trip, NAN-S01 and NAN-S02 are fed from the auxiliary transformer, and are fed from NAN-S03 and NAN-S04 respectively after the plant trip.

Each DG must be capable of starting, accelerating to rated speed (i.e., frequency) and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. 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 condition with the engine hot and DG in standby condition with the engine at normal keep-warm conditions. Additional DG capabilities must be demonstrated to meet required Surveillances (e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode).

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

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

APPLICABILITY

The AC sources and sequencers 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.

(continued)

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are covered in LCO 3.8.2, "AC Sources – Shutdown."

ACTIONS

Condition A applies only when the offsite circuit is unavailable to commence automatic load sequencing in the event of a design basis accident (DBA). In cases where the offsite circuit is available for sequencing, but a DBA could cause actuation of the Degraded Voltage Relays, Condition G applies.

A.1

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

A.2

Required Action A.2, which only applies if the train (i.e., ESF bus) cannot be powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and include: charging pumps; radiation monitors Train A RU-29 and Train B RU-30 (TS 3.3.9), Train A RU-31 and Train B RU-145; pressurizer heaters (TS 3.4.9); ECCS (TS 3.5.3 and TS 3.5.4); containment spray (TS 3.6.6); containment isolation valves NCA-UV-402, NCB-UV-403, WCA-UV-62, and WCB-UV-61 (TS 3.6.3); containment hydrogen monitors (TS 3.3.10); hydrogen recombiners (TS 3.6.7); auxiliary feedwater system (TS 3.7.5); essential cooling water system (TS 3.7.7); essential spray pond system (TS 3.7.8); essential chilled water system (TS 3.7.10); control room essential filtration system (TS 3.7.11); control room emergency air temperature control

(continued)

BASES

ACTIONS

A.2 (continued)

system (TS 3.7.12); ESF pump room air exhaust cleanup system (TS 3.7.13); shutdown cooling subsystems (TS 3.4.6, 3.4.7, 3.4.8, and 3.4.15); and fuel building ventilation. Mode applicability is as specified in each appropriate TS section.

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

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

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

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

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

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

(continued)

BASES

ACTIONS (continued)

A.3

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

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

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

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

(continued)

BASES

ACTIONS (continued)

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of redundant required features. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

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

a. An inoperable DG exists; and

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

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

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action.

(continued)

BASES

ACTIONS

B.2 (continued)

Four hours from the discovery of these events existing concurrently, is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

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

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

(continued)

BASES

ACTIONS (continued)

B.4

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

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

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

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

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. These features require Class 1E power from PBA-S03 or PBB-S04 ESF buses to be OPERABLE, and are identical to those specified in ACTION A.2. Mode applicability is as specified in each appropriate TS section.

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

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

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

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

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

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

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

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

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C applies only when the offsite circuits are unavailable to commence automatic load sequencing in the event of a design basis accident (DBA). In cases where the offsite circuits are available for sequencing, but a DBA could cause actuation of the Degraded Voltage Relays, Condition G applies.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to a train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

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

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

(continued)

BASES

ACTIONS (continued)

E.1

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

According to Regulatory Guide 1.93 (Ref. 6), with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

The sequencer(s) is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the load group. The 24 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal. Required Action F.2 is intended to provide assurance that a single failure of a DG Sequencer will not result in a complete loss of safety function of critical redundant required features.

G.1 and G.2

To ensure offsite circuits will not be lost as a consequence of a DBE, certain voltage and loading conditions must be maintained. Failure to maintain these conditions may result in double sequencing should an accident requiring sequencer operation occur.

The operability of the offsite circuits is assured by maintaining

$$MVA_{pred} \leq MVA_{\max}$$

Where:

MVA_{pred} = predicted post-trip loading as discussed below

MVA_{max} = maximum allowable post-trip loading as discussed below

Predicted Post-Trip Loading (MVA_{pred})

Predicted post-trip loading is the highest loading, in MVA (megavolt-amperes), that would be expected to be supplied by the associated startup transformer secondary winding

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

immediately after the completion of the automatic load sequencing resulting from a LOCA or other design basis accident. The magnitude of post-trip loading is affected by several switching conditions. The loads for each of the load blocks that would be connected to the offsite circuit (i.e., startup transformer secondary winding) immediately after sequencing would be summed to determine the predicted post-trip loading. The loads for each of the load blocks are listed in the following table:

Load Block	When Load Block Must be Included	Load (MVA)
1. Emergency loads on EPBAS03 or EPBBS04.	Always.	6
2. House loads on ENANS01 or ENANS02.	When the offsite circuit is feeding the house loads or fast bus transfer is enabled.	43 or as measured
3. Other load groups bus NBNS01 or NBNS02.	When load block 2 is included and it is feeding the other load group's NB bus via tie breaker ENBNS01C.	8 or as measured
4. Other unit's non-accident Class 1E loads on EPBAS03 or EPBBS04.	When the offsite circuit is feeding another unit's Class 1E loads.	3 or as measured
5. Water Reclamation Facility (WRF) loads on 1ENANS05 or 1ENANS06.	When the offsite circuit is feeding the WRF.	10 or as measured
6. Other common loads on 1ENANS05 or 1ENANS06.	When the offsite circuit is feeding non-WRF common loads.	3 or as measured

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

Maximum Post-Trip Loading (MVA_{max})

The maximum allowable post-trip loading is based on the following:

- If the unit under consideration is not the only Palo Verde unit available to regulate the switchyard voltage (one or both of the other Palo Verde units online and available to regulate the switchyard voltage, or the unit under consideration not capable of regulating switchyard voltage), $MVA_{max} = (KV - 490) \times 2$ where KV = steady state switchyard kilovolts. A voltage dip lasting less than 35 seconds is considered a transient, rather than a steady-state, condition, and would not require evaluation.

- If the unit under consideration is the only Palo Verde unit available to regulate the switchyard voltage and all five 525 kV lines are in service (Devers, Kyrene, North Gila, Westwing 1, and Westwing 2), MVA_{max} = 50.8 MVA.

- If the unit under consideration is the only Palo Verde unit available to regulate the switchyard voltage and four of the five 525 kV lines are in service, MVA_{max} = 44 MVA.

- If the unit under consideration is the only Palo Verde unit available to regulate the switchyard voltage and less than four 525 kV lines are in service, the offsite circuits do not meet their required capability.

The formula for MVA_{MAX} is based on calculations, 01, 02, 03-EC-MA-221, which analyze many different bus alignment conditions. The load limit is conservative, with sufficient margin to account for analytical uncertainties and to provide assurance that the degraded voltage relays will not actuate as a result of an accident.

If one or more of the other Palo Verde units is online and available to regulate switchyard voltage, the voltage will not change significantly following an accident in the unit under consideration. Therefore, the steady-state pre-trip

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

voltage can be used in the formula which calculates MVA_{MAX}. The voltage used in the formula is the actual switchyard voltage. Therefore, loop uncertainty of the measuring equipment, as determined by Engineering, must also be taken into account. A voltage dip lasting 35 seconds or less is considered a transient, rather than steady-state, condition based on the credited 35 second time delay of the degraded voltage relay.

If an accident results in a loss of local switchyard voltage control (last operating unit trips), transmission system studies have concluded that the switchyard voltage will stabilize at or above 515.4 kV with all transmission lines in service, and 512 kV with four transmission lines in service. At these switchyard voltages, control of MVA_{PRED} at or below the allowed MVA_{MAX} assures that the degraded voltage relays will not actuate.

If the required capability in Condition G is not met, the effects of an AOO or DBA could cause further depression of the voltage at the ESF bus and actuation of the degraded voltage relays. These actuations would result in disconnection of the bus from the offsite circuits. Regulatory Guide 1.93 (Ref. 6) defines this condition as "The Available Offsite Power Sources Are One Less Than the LCO" or "The Available Offsite AC Power Sources Are Two Less Than the LCO," depending on the number of affected circuits. However, degraded post-trip voltage could also cause ESF electrical equipment to be exposed to a degraded condition during the degraded voltage relay time-out period. There is a risk that equipment misoperation or damage could occur during this time. In this scenario, the ESF equipment may not perform as designed following an automatic disconnection of the offsite circuits and reconnection to the diesel generators (DGs), even though adequate power is available from the DG. For certain DBAs, an additional consideration is that the initial sequencing of the ESF equipment onto the offsite circuits, subsequent tripping of the degraded voltage relays, and interruption in equipment credited in the UFSAR Chapter 6 and 15 safety analyses could challenge the credited equipment response times. Therefore, it is appropriate to implement Required Actions that are more stringent than those specified in Condition A or C.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

If the required capability in Condition G is not met, the following options are available to restore full or partial Operability. Options are listed in their order of preference.

1. Improve post-trip switchyard voltage. In most cases this can be accomplished by raising the VAR output of one or more of the operating Palo Verde units. However, if only one Palo Verde unit is operating, that unit's VAR output would be lost if it were to trip regardless of its pre-trip level, so other changes to the grid operation would need to be implemented to improve the post-trip voltage. There are a number of methods that the Energy Control Center may be able to implement to achieve this.

2. Reduce post-trip loading. One way that this could be accomplished is by disabling fast bus transfer. Although Palo Verde has no formal restrictions on the amount of time that fast bus transfer can be out of service, this option should be used judiciously in order to maintain forced circulation capability. Besides blocking fast bus transfer, there may be other methods available to reduce the loading, such as removing loads or realigning equipment power sources.

3. Transfer the safety bus(es) to the diesel generator(s). This is less desirable than option 2, because it would perturb the plant. It would cause the plant to remain in an LCO 3.8.1 condition (A or C, depending on whether one or two buses are transferred).

Options 1 and 2 satisfy Required Action G.1, and Option 3 satisfies Required Action G.2. With more than one offsite circuit that does not meet the required capability, Condition G could be satisfied for each offsite circuit by the use of Required Action G.1 or G.2. The Completion Time for both Required Action G.1 and G.2 is one hour. The one hour time limit is appropriate and consistent with the need to remove the unit from this condition, because the level of degradation exceeds that described in Regulatory Guide 1.93 (Ref. 6) for two offsite circuits inoperable. The

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

regulatory guide assumes that an adequate onsite power source is still available to both safety trains, but in a scenario involving automatic load sequencing and low voltage to the ESF buses, adequate voltage is not assured from any of the power sources for the following systems immediately after the accident signal has been generated (i.e., while the degraded voltage relay is timing out): radiation monitors Train A RU-29 or Train B RU-30 (TS 3.3.9), Train B RU-145; ECCS (TS 3.5.3); containment spray (TS 3.6.6); containment isolation valves (TS 3.6.3); auxiliary feedwater system (TS 3.7.5); essential cooling water system (TS 3.7.7); essential spray pond system (TS 3.7.8); essential chilled water system (TS 3.7.10); control room essential filtration system (TS 3.7.11); ESF pump room air exhaust cleanup system (TS 3.7.13); and fuel building ventilation.

Required Action G.2 is modified by a Note. The reason for the Note is to ensure that the offsite circuit is not inoperable for a time greater than the Completion Time allowed by LCO 3.8.1 Condition A or C. Therefore, if Conditions A or C are entered, the Completion Time clock for Conditions A and C would start at the time Condition G was entered.

H.1 and H.2

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

(continued)

BASES

ACTIONS (continued)

I.1

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

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions).

The SR for demonstrating OPERABILITY of the DGs are based on the recommendations of Regulatory Guide 1.9 (Ref. 3), unless otherwise noted in the Updated FSAR Section 1.8.

The DG capabilities (starting and loading) are required to be met from a variety of initial conditions such as DG in standby condition with the engine hot (SR 3.8.1.15) and DG in standby condition with the engine at normal keep-warm conditions (SR 3.8.1.2, SR 3.8.1.7 and SR 3.8.1.19). Although it is expected that most DG starts will be performed from normal keep-warm conditions, DG starts should be performed with the jacket water cooling and lube oil temperatures within the lower to upper limits of DG OPERABILITY, except as noted above. Rapid cooling of the DG down to normal keep-warm conditions should be minimized.

The required steady state frequency range for the DG is 60 +1.2/-0.3 Hz to be consistent with the safety analysis to provide adequate safety injection flow. In accordance with the guidance provided in Regulatory Guide 1.9 (Ref. 3), where steady state conditions do not exist (i.e., transients), the frequency range should be restored to within ± 2% of the 60 Hz nominal frequency (58.8 Hz to 61.2 Hz).

Specific MODE restraints have been footnoted where applicable to each 18 month SR. The reason for "This Surveillance shall not be performed in MODE 1 or 2" is that

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

during operation with the reactor critical, performance of this SR could cause perturbations to the EDS that could challenge continued steady state operation and, as a result, unit safety systems; or that performing the SR would remove a required DG from service. The reason for "This Surveillance shall not be performed in MODE 1, 2, 3, or 4" is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems.

SR 3.8.1.1

This SR assures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and indicated availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

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

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

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

In order to reduce stress and wear on diesel engines, the DG manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. This is the intent of Note 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions with the engine at normal keep-warm conditions and achieves required voltage and frequency within 10 seconds, and subsequently achieves steady state required voltage and frequency ranges. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 15 (Ref. 5).

A minimum voltage and frequency is specified rather than an upper and a lower limit because a diesel engine acceleration at full fuel (such as during a fast start) is likely to "overshoot" the upper limit initially and then go through several oscillations prior to a voltage and frequency within the stated upper and lower bounds. The time to reach "steady state" could exceed 10 seconds, and be cause to fail the SR. However, on an actual emergency start, the EDG would reach minimum voltage and frequency in ≤ 10 seconds at which time it would be loaded. Application of the load will dampen the oscillations. Therefore, only specifying the minimum voltage and frequency (at which the EDG can accept load) demonstrates the necessary capability of the EDG to satisfy safety requirements without including a potential for failing the Surveillance.

While reaching minimum voltage and frequency in ≤ 10 seconds is an immediate test of OPERABILITY, the ability of the governor and voltage regulator to achieve steady state operation, and the time to do so are important indicators of continued OPERABILITY. Therefore, the time to achieve steady state voltage and frequency will be monitored as a function of continued OPERABILITY.

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, 10 second start requirement of SR 3.8.1.7 applies.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

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

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads of 90 to 100 percent (4950 - 5500 kW) of the continuous rating of the DG. Consistent with the guidance provided in the Regulatory Guide 1.9 (Ref. 3) load-run test description, the 4950 - 5500 kW band will demonstrate 90 to 100 percent of the continuous rating of the DG. The load band (4950 - 5500 kW) is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band for special testing may be performed within the guidance of the generator capability curve.

A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

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

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients because of changing bus loads do not invalidate this test. 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 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

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

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 92 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and 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. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

Since the design of the fuel transfer system is such that pumps will operate automatically in order to maintain an adequate volume of fuel oil in the day tank during or following DG testing, a 31 day Frequency is appropriate.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the auto-connected emergency loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load, or equivalent load, without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. Train A Normal Water Chiller (at 842 kW) and Train B AFW pump (at 936 kW) are the bounding loads for the DG A and DG B to reject, respectively. These values are listed in Table 8.3-3, Load Bases for Class 1E Buses, in the Updated FSAR (Ref. 2). This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by IEEE-308 (Ref. 12), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of a typical 5 second load sequence interval associated with sequencing of the largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

This SR is modified by a Note. The reason for the Note is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems. This SR is performed in emergency mode (not paralleled to the grid) ensuring that the DG is tested under load conditions that are as close to design basis conditions as possible.

SR 3.8.1.10

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

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the guidance of Regulatory Guide 1.9 (Ref. 3). Consistent with the guidance provided in the Regulatory Guide 1.9 full-load rejection test description, the 4950 - 5500 kW band will demonstrate the DG's capability to reject a load equal to 90 to 100 percent of its continuous rating. Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result, power factors deviating much from unity are currently not possible when the DG runs parallel to the grid. To the extent practicable, VARs will be provided by the DG during this SR.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.8 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 10 seconds is derived from requirements of the accident analysis. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or shutdown cooling (SDC) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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 to the extent possible ensuring power is available to the component.

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 three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Note 3 states that momentary voltage and frequency transients induced by load changes do not invalidate this test.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis accident signal (LOCA) signal, and subsequently achieves steady state required voltage and frequency ranges, and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and auto-connected emergency loads (auto-connected through the automatic load sequencer) are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent and auto-connected emergency loads is intended to satisfactorily show the relationship of these loads to the offsite circuit loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

capable of being operated at full flow, or SDC systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the offsite circuit 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 to the extent possible ensuring power is available to the component.

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. The reason for Note 2 is that performing this SR would remove a required offsite circuit from service, perturb the EDS, and challenge safety systems.

SR 3.8.1.13

This Surveillance demonstrates that DG noncritical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, generator differential current, engine low lube oil pressure, and manual emergency stop trip), trip the DG to avert substantial damage to the DG unit. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.13 (continued)

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 reason for the Note is that performing the Surveillance would remove a required DG from service.

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, 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 105 to 110% of the continuous rating of the DG (5775 - 6050 kW) and ≥ 22 hours at a load equivalent to 90 to 100% of the continuous duty rating of the DG (4950 - 5500 kW). The DG starts for this Surveillance can be performed either from normal keep-warm 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 (Note 3 and Note 4).

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing is performed using design basis kW loading and maximum kVAR loading permitted during testing. These loads represent the inductive loading that the DG would experience to the extent practicable and is consistent with the intent of Regulatory Guide 1.9 (Ref. 3). Administrative limits have been placed upon the Class 1E 4160 V buses due to high voltage concerns. As a result, power factors deviating much from unity are currently not possible when the DG runs parallel to the grid. To the extent practicable, VARs will be provided by the DG during this SR. 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, 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 four Notes. Note 1 states that momentary variations due to changing bus loads do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. The 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 (Note 3 and Note 4).

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, and subsequently achieves steady state required voltage and frequency ranges. 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), paragraph 2.2.10.

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. Per the guidance in Regulatory Guide 1.9, this SR would demonstrate the hot restart functional capability at full-load temperature conditions, after the DG has operated for 2 hours (or until operating temperatures have stabilized) at full load. Momentary transients due to changing bus loads do not invalidate the 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.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start 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, in standby operation (running unloaded), the output breaker is open and can receive an autoclose signal on bus undervoltage, and the load sequence timers are reset.

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

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

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 (e.g., simulated SIAS) is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage, in standby operation (running unloaded) with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 12), paragraph 6.2.6(2) and Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.13.

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

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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

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 1 second load sequence time tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. FSAR, Chapter 8 (Ref. 2) provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4; takes into consideration unit conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

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

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

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

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

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

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

SR 3.8.1.20

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

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.3.2.4 and Regulatory Guide 1.137 (Ref. 9).

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.20 (continued)

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the EDS that could challenge continued steady state operation and, as a result, unit safety systems.

REFERENCES:

1. 10 CFR 50, Appendix A, GDC 17
2. Updated FSAR, Chapter 8
3. Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," July 1993.
4. Updated FSAR, Chapter 6
5. Updated FSAR, Chapter 15
6. Regulatory Guide 1.93, "Availability of Electric Power Sources," Revision 0, December 1974.
7. GL 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18
9. Regulatory Guide 1.137, "Fuel Oil Systems for Standby Diesel Generators," Revision 1, October 1979.
10. ANSI C84.1-1982
11. IEEE Standard 308-1974, "IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations."

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BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 6) and Chapter 15 (Ref. 7), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

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

LCO

The DC electrical power subsystems, each subsystem consisting of two batteries, battery charger for each battery (the backup battery charger, one per train, may be used to satisfy this requirement), and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

Each DC electrical power subsystem (Train A or Train B) is subdivided into channels. Train A consists of Channel A and Channel C. Train B consists of Channel B and Channel D.
Channel A includes 125 VDC bus PKA-M41, 125 VDC battery bank PKA-F11, and normal battery charger PKA-H11 or backup battery charger PKA-H15.
Channel C includes 125 VDC bus PKC-M43, 125 VDC battery bank PKC-F13, and normal battery charger PKC-H13 or backup battery charger PKA-H15.

(continued)

BASES

Channel B includes 125 VDC bus PKB-M42, 125 VDC battery bank PKB-F12, and normal battery charger PKB-H12 or backup battery charger PKB-H16.
Channel D includes 125 VDC bus PKD-M44, 125 VDC battery bank PKD-F14, and normal battery charger PKD-H14 or backup battery charger PKB-H16.

An OPERABLE DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC bus(es).

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and 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 integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 5 and 6, and during movement of irradiated fuel assemblies are addressed in the Bases for LCO 3.8.5, "DC Sources – Shutdown."

ACTIONS

A.1

Condition A represents one train with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. This condition is exclusive of the status of one battery charger. It is therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required DC electrical power subsystems is inoperable (exclusive of the battery charger), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure would, however, result in the complete loss of the remaining 125 VDC electrical

(continued)

BASES

power subsystem with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

Entry into Condition A is not required with one of the required (in-service) battery chargers inoperable. When one of the required (in-service) battery chargers is inoperable, Condition C is appropriate to enter. The loss of two required (in-service) battery chargers on the same train would be a degradation of the train beyond the scope of Condition C, thus rendering the train inoperable and requiring entry into Condition A.

B.1 and B.2

If the inoperable DC electrical power subsystem (exclusive of the battery charger) cannot be restored to OPERABLE status within the required Completion Time of Condition A, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 8).

C.1 and C.2

Condition C represents the loss of one of the required (in-service) battery chargers and assumes that action will be taken immediately to restore charging capability to the battery with the alternate charger (i.e., normal or backup). Under normal plant load conditions, the loss of the battery charger for ≤ 1 hour has a negligible effect on the rated battery capacity and does not impact the DC electrical power subsystem's capability to perform its DBA safety function. Immediately following the loss of the charging capability, battery cell parameters may not meet Category A limits because these limits assume that the battery is being charged at a minimum float voltage. The 1 hour Completion

(continued)

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ACTIONS

C.1 and C.2 (continued)

Time allows for re-establishing charging capability such that Category A parameters can be met. Operation with the DC electrical power subsystem battery charger inoperable is not allowed for an indefinite period of time even when the battery cell parameters have been verified to meet the Category A limits of Table 3.8.6-1. The 24 hour completion time provides a period of time to correct the problem commensurate with the importance of maintaining the DC electrical power subsystem battery charger in an OPERABLE status.

The loss of the two required (in-service) battery chargers on the same train would be a degradation of the train beyond the scope of Condition C, thus rendering the train inoperable and requiring entry into Condition A.

D.1

If the battery cell parameters cannot be maintained within Category A limits as specified in LCO 3.8.6, the short term capability of the battery is also degraded and the battery must be declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculation. The 7 day Frequency is more conservative than the frequency specified in IEEE-450 (Ref. 9).

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.2

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The limits established for this SR are based on calculation 1,2,3ECPK207 which states that if every terminal connection were to degrade to 150E-6 ohms, there would be sufficient battery capacity to satisfy the DBA Duty Cycle (Ref. 13).

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. The presence of physical damage or deterioration does not necessarily represent a failure of this SR, provided an evaluation determines that the physical damage or deterioration does not affect the OPERABILITY of the battery (its ability to perform its design function).

This SR is consistent with IEEE-450 (Ref. 9), which recommends detailed visual inspection of cell condition and rack integrity. The 18 month Surveillance Frequency is consistent with expected fuel cycle length, minimizing battery testing while on line that could result in rendering the batteries inoperable.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.4.

The connection resistance limits for SR 3.8.4.5 is based on calculation 1,2,3ECPK207 which states that if every terminal connection were to degrade to 150E-6 ohms there would be sufficient battery capacity to satisfy the DBA Duty Cycle (Ref. 13).

The Surveillances are consistent with IEEE-450 (Ref. 9), which recommends cell to cell and terminal connection resistance measurement. The 18 month Surveillance Frequency is consistent with expected fuel cycle length, minimizing battery testing while on line that could result in rendering the batteries inoperable.

SR 3.8.4.6

This SR requires that each required battery charger be capable of supplying 400 amps for batteries A and B and 300 amps for batteries C and D, and 125 V for ≥ 8 hours. These requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle length.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance on the charger credited for OPERABILITY would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.7

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

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 battery performance discharge test or a modified performance discharge test in SR 3.8.4.8 in lieu of a service test since both performance discharge test parameters envelope the service test. The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the "as found" condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

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 (but in no case lower than the performance test rate), 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.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm 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 should be identical to those specified for a service test.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8. In addition, either of the performance discharge tests may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time, because the test parameters envelope the service test described in SR 3.8.4.7.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer rating. A capacity of 80% (low specific gravity cells) or 90% (AT&T) shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated when the battery capacity drops by more than 10% (low specific gravity cells) or 5% (AT&T) relative to its capacity on the previous performance test, or when it is ≥ 10% (low specific gravity cells) or ≥ 5% (AT&T) below the manufacturer's rating.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. 10 CFR.50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1974.
4. UFSAR, Chapter 8.3.2.
5. IEEE-485-1983, June 1983.
6. UFSAR, Chapter 6.
7. UFSAR, Chapter 15.
8. Regulatory Guide 1.93, December 1974.
9. IEEE-450-1980.
10. Regulatory Guide 1.32, Revision 0, August 11, 1972.
11. Regulatory Guide 1.129, Revision 1, February 1978.
12. Design Basis Manual "Class 1E 125 VDC Power System".
13. Calculation 1,2,3ECPK207

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BASES

ACTIONS

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

minimize the time during which the unit safety systems may be without sufficient power.

Entry into Condition A is not required with one of the required (in-service) battery chargers inoperable. When one of the required (in-service) battery chargers is inoperable, Condition B is appropriate to enter. The loss of two required (in-service) battery chargers on the same train would be a degradation of the train beyond the scope of Condition B, thus rendering the train inoperable and requiring entry into Condition A.

B.1 and B.2

Condition B represents the loss of one of the required (in-service) battery chargers and assumes that action will be taken immediately to restore charging capability to the battery with the alternate charger (i.e., normal or backup). Under normal plant load conditions, the loss of the battery charger for ≤ 1 hour has a negligible effect on the rated battery capacity and does not impact the DC electrical power subsystem's capability to perform its DBA safety function. Immediately following the loss of the charging capability, battery cell parameters may not meet Category A limits because these limits assume that the battery is being charged at a minimum float voltage. The 1 hour Completion Time allows for re-establishing charging capability such that Category A parameters can be met. Operation with the DC electrical power subsystem battery charger inoperable is not allowed for an indefinite period of time even when the battery cell parameters have been verified to meet the category A limits of Table 3.8.6-1. The 24 hours completion time provides a period of time to correct the problem commensurate with the importance of maintaining the DC electrical power subsystem battery charger in an OPERABLE status.

The loss of the two required (in-service) battery chargers on the same train would be a degradation of the train beyond the scope of Condition B, thus rendering the train inoperable and requiring entry into Condition A.

(continued)

BASES

ACTIONS (continued)

C.1

If the battery cell parameters cannot be maintained within Category A limits as specified in LCO 3.8.6, the short term capability of the battery is also degraded and the battery must be declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 states that Surveillances required by SR 3.8.4.1 through SR 3.8.4.8 are applicable in these MODES. See the corresponding Bases for LCO 3.8.4 for a discussion of each SR. This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.