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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Subject: Technical Specification Bases Changes
Cooper Nuclear Station
NRC Docket No. 50-298, DPR-46

In accordance with the requirements of Cooper Nuclear Station Technical Specification 5.5.10.d and 10 CFR 50.71(e), enclosed are changes to the Technical Specification Bases implemented without prior Nuclear Regulatory Commission approval for the current reporting period of June 22, 2002 to August 15, 2003 inclusive.

If you have any questions regarding this submittal, please contact Mr. Paul Fleming at 402-825-2774.

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BASES

SR 3.0.2 (continued)

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of the regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been

BASES

SR 3.0.3 (continued)

performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not to have been performed when specified, SR 3.0.3 allows the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, 'Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.'

BASES

SR 3.0.3 (continued)

This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change.

BASES

SR 3.0.4 (continued)

When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed per SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency, on equipment that is inoperable, does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

SR 3.0.4 is only applicable when entering MODE 3 from MODE 4, MODE 2 from MODE 3 or 4, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODE 1, 2, or 3. The requirements of SR 3.0.4 do not apply in MODES 4 and 5, or in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

BASES

ACTIONS

D.1 (continued)

ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the accumulator pressure be checked every 7 days to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of 1100 psig. Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. USAR, Section III-5.
2. USAR, Section VII-2.
3. USAR, Appendix F.
4. 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Intermediate Range Monitor Inop (continued)

Since this Function is not assumed in the safety analysis, there is no Allowable Value for this Function.

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux-High Function is required.

Average Power Range Monitor

2.a. Average Power Range Monitor Neutron Flux-High (Startup)

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core that provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux-High (Startup) Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux-High (Startup) Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux-High Function because of the relative setpoints. With the IRMs at Range 9, it is possible that the Average Power Range Monitor Neutron Flux-High (Startup) Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux-High (Startup) Function. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

system from each SDV. The level measurement instrumentation satisfies the recommendations of Reference 9.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in each SDV to accommodate the water from a full scram.

For each Scram Discharge Volume Water Level-High Function (i.e., for each SDV), there is one channel of each type (type 7.a and 7.b) in each trip system. Since Table 3.3.1.1-1 provides the total number of required channels per trip system for both SDVs, a total of two required channels of each type per trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve-Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve-Closure Function is the primary scram signal for the turbine trip, feedwater controller failure maximum demand, and the loss of main condenser vacuum events analyzed in Reference 2. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Stop Valve-Closure signals are initiated from position switches located on each of the two TSVs. Two independent position switches are associated with each stop valve. Both of the switches from one TSV provide input to RPS trip system A; the two switches from the other TSV provide input to RPS trip system B. Thus, each RPS trip system receives two Turbine Stop Valve-Closure channel inputs from a TSV, each consisting of one position switch assembly with two contacts, each inputting to a relay. The relays provide a parallel logic input to an RPS trip logic channel. The logic for the Turbine Stop Valve-Closure Function is such that both TSVs must be closed to produce a scram. Single valve

BASES

APPLICABLE, SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

closure will produce a half scram. This Function must be enabled at THERMAL POWER ≥ 30% RTP as measured by turbine first stage pressure. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

The Turbine Stop Valve-Closure Allowable Value is selected to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Four channels of Turbine Stop Valve-Closure Function, with two channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if both TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Pressure-High and the Average Power Range Monitor Neutron Flux-High (Fixed) Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 2. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, DEH Trip Oil Pressure-Low signals are initiated by low digital-electrohydraulic control (DEHC) fluid pressure in the emergency trip header for the control valves. There are four pressure switches which sense off the common header, with one pressure switch assigned to each separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 30% RTP as measured by turbine first stage pressure. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening the turbine bypass valves may affect this Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLITY

3.e. Suppression Pool Water Level-High (continued)

OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.f. High Pressure Coolant Injection Pump Discharge Flow-Low (Bypass)

The minimum flow instrument is provided to protect the HPCI pump from overheating when the pump is operating at reduced flow. The minimum flow line valve is opened when low flow is sensed and either 1) the pump is on, or 2) the system has initiated; and the valve is automatically closed when the flow rate is adequate to protect the pump. The High Pressure Coolant Injection Pump Discharge Flow — Low Function is assumed to be OPERABLE. The minimum flow valve for HPCI is not required to close to ensure that the ECCS flow assumed during the transients analyzed in References 5, 6, and 7 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch is used to detect the HPCI System's flow rate. The logic is arranged such that the switch causes the minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded.

The High Pressure Coolant Injection Pump Discharge Flow — Low Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump.

One channel is required to be OPERABLE when the HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level-Low Low Low (Level 1)

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1.3 (continued)

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. USAR, Section VIII-4.6.
2. USAR, Chapter XIV.
3. 10 CFR 50.36(c)(2)(ii)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND

The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell fan coil units remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 4 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment and equipment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Refs. 1 and 4). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 2). Analyses assume an initial average drywell air temperature of 150°F. The 150°F limit ensures that adequate ECCS NPSH is maintained and that the peak LOCA drywell temperature does not exceed the maximum allowable structural temperature of 281°F. Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident.

Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36 (c)(2)(ii) (Ref. 3).

LCO

In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant drywell structural temperature is maintained below the maximum allowable. As a result, the ability of primary containment to perform its design function is ensured.

BASES

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

ACTIONS

A.1

With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to allow significant variations in this parameter, and provides sufficient time to correct minor problems.

B.1 and B.2

If the drywell average air temperature cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. Drywell air temperature is monitored in various areas and at various elevations (referenced to mean sea level) within Primary Containment. Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (References 1 and 2). An initial pool temperature of 95°F is assumed for the Reference 1 and Reference 2 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool temperature of 120°F are assumed for the Reference 3 and 4 analyses. The limit of 105°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing.

Suppression pool average temperature satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are:

a. Average temperature ≤ 95°F when THERMAL POWER is > 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 105°F when THERMAL POWER is > 1% RTP and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 95°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 95°F is short enough not to cause a significant increase in unit risk.

BASES

ACTIONS

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

experience. Given the high suppression pool average temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained at ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours, and the plant must be brought to at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk temperature could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.2.1.1 (continued) on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.
REFERENCES	1. USAR, Section V-2. 2. USAR, Section XIV-6. 3. USAR, Section XIV-5. 4. NEDC 94-034D. 5. 10 CFR 50.36(c)(2)(ii).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1 (continued)

position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the system is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

SR 3.6.2.3.2

Verifying that each RHR pump develops a flow rate $\geq$ 7700 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME Code, Section XI (Ref. 4). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

REFERENCES

1. USAR, Section XIV-6.
2. 10 CFR 36(c)(2)(ii).
3. NEDC 94-034B, C & D
4. ASME, Boiler and Pressure Vessel Code, Section XI.

BASES

APPLICABLE SAFETY ANALYSES (continued)

level equates to a level of at least 863.2 ft mean sea level in the SW pump bay under postulated worst case conditions. This level exceeds the 862.8 ft mean sea level submergence requirements for necessary long term SW cooling. The ability of the SW System to support long term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the USAR, Chapters V and XIV (Refs. 2 and 3, respectively). These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The ability of the SW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 2 and 3. The ability to provide onsite emergency AC power is dependent on the ability of the SW System to cool the DGs. The long term cooling capability of the RHR, core spray, and RHRSWB pumps is also dependent on the cooling provided by the SW System.

The SW System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

The SW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of SW is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of SW must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has an OPERABLE UHS, two OPERABLE pumps, and an OPERABLE flow path capable of taking suction from the intake structure and transferring the water to the appropriate equipment.

The OPERABILITY of the UHS is based on having a minimum river water level of 865 ft mean sea level and a maximum water temperature of 95°F.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

pumps per loop are required to be OPERABLE to satisfy the requirements of the LCO.

The ability of the REC System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in Reference 1.

The REC System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

The REC subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of REC is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of REC must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has two OPERABLE pumps, one OPERABLE heat exchanger, and an OPERABLE flow path capable of transferring the water to the appropriate equipment. Each REC subsystem's OPERABILITY requires that its service water backup cross tie valves be OPERABLE.

The OPERABILITY of the REC System is also based on verifying the REC surge tank water level is within limits and a maximum supply water temperature of 100°F.

The isolation of the REC System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the REC System.

APPLICABILITY

In MODES 1, 2, and 3, the REC System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the REC System. Therefore, the REC System is required to be OPERABLE in these MODES.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources — Operating

BASES

BACKGROUND

The unit AC Sources for the Class 1E AC Electrical Power Distribution System consist of the offsite power sources (preferred power sources, normal and alternates), and the onsite standby power sources (diesel generators (DGs)). As required by USAR, Appendix F (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant load groups, so loss of any one group does not prevent the minimum safety functions from being performed. Each load group has connections to two qualified offsite power supplies and a single DG.

The offsite power sources are a startup station service transformer (SSST) which connects to the 161 kV switchyard and a separate emergency station service transformer (ESST) energized by a 69 kV line. The 161 kV switchyard is connected to one 161 kV line which terminates in a switchyard near Auburn, Nebraska, and the 345/161 kV, 300 MVA auto-transformer which connects to the 345 kV switchyard. The 345 kV switchyard has five lines which terminate in switchyards near Booneville, Iowa; Hallam, Nebraska; St. Joseph, Missouri; Fairport, Missouri; and Nebraska City, Nebraska. The ESST is fed by a 69 kV line which is part of a subtransmission grid of the Omaha Public Power District. If the normal station service transformer (NSST) (powered by the main generator) is lost, the SSST, which is normally energized, will automatically energize 4160 volt buses 1A and 1B, as well as their connected loads, including critical buses 1F & 1G. If the SSST fails to energize the critical buses, the ESST, which is normally energized, will automatically energize both critical buses. If the ESST were also to fail, the emergency diesel generators would automatically energize their respective buses. A detailed description of the offsite power network and circuits to the onsite Class 1E critical buses is found in the USAR, Sections VIII-2.0 and VIII-3.0 (Ref. 2).

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11 (continued)

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 plant 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 being periodically circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. USAR, Appendix F.
2. USAR, Section VIII-2.0 and VIII-3.0.
3. Safety Guide 9, Revision 0, March 1971.
4. USAR, Chapter VI.
5. USAR, Chapter XIV.
6. 10 CFR 50.36(c)(2)(ii).
7. Generic Letter 84-15.
8. Regulatory Guide 1.93.
9. Regulatory Guide 1.9, Revision 3, July 1993.
10. Regulatory Guide 1.108.
11. Regulatory Guide 1.137.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.8 (continued)

The 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 18 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 7), when the battery capacity drops by more than 10% relative to its capacity on the previous performance tests or when it is below 90% of the manufacturer's rating. The 60 month frequency is consistent with the recommendations in IEEE-450 (Ref. 7). The 18 month and 24 month Frequencies are derived from the recommendations in IEEE-450 (Ref. 7)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. USAR, Section VIII-6.2.
2. Regulatory Guide 1.6.
3. IEEE Standard 308, 1970.
4. USAR, Chapter XIV.
5. 10 CFR 50.36(c)(2)(ii).
6. Regulatory Guide 1.93.
7. IEEE Standard 450, 1995.
8. Regulatory Guide 1.32, February 1977.

ATTACHMENT 3 LIST OF REGULATORY COMMITMENTS©

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The following table identifies those actions committed to by Nebraska Public Power District (NPPD) in this document. Any other actions discussed in the submittal represent intended or planned actions by NPPD. They are described for information only and are not regulatory commitments. Please notify the Licensing & Regulatory Affairs Manager at Cooper Nuclear Station of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	COMMITTED DATE OR OUTAGE
None	