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APR 10 2012

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

Serial No. 12-111
LIC/NW/R0
Docket No.: 50-305
License No.: DPR-43

DOMINION ENERGY KEWAUNEE, INC.
KEWAUNEE POWER STATION
TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

Pursuant to Kewaunee Power Station (KPS) Technical Specification 5.5.12, "Technical Specifications (TS) Bases Control Program," Dominion Energy Kewaunee, Inc. (DEK) hereby submits changes to the TS Bases.

Additionally, DEK submits changes to the KPS Technical Requirements Manual (TRM). 10 CFR 50.71(e)(4) states the requirements for submittal of the KPS Updated Safety Analysis Report (USAR). As the KPS TRM is considered a part of the USAR by reference, it is also required to be submitted to the Nuclear Regulatory Commission.

The attachments provide copies of the KPS TS Bases, TRM pages, and TRM current page list reflecting the changes implemented since April 2011.

The changes to the TS Bases and TRM were made in accordance with the provisions of 10 CFR 50.59 and approved by the KPS Facility Safety Review Committee.

If you have questions or require additional information, please feel free to contact Mr. Jack Gadzala at 920-388-8604.

Very truly yours,

A. J. Jordan
Site Vice President, Kewaunee Power Station

A001
NRR

Attachments:
1. Kewaunee Power Station Technical Specifications Bases Changes
2. Kewaunee Power Station Technical Requirements Manual Changes
3. Kewaunee Power Station Technical Requirements Manual Current Page List

Commitments made by this letter: NONE

cc: Regional Administrator, Region III
U. S. Nuclear Regulatory Commission
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NRC Senior Resident Inspector
Kewaunee Power Station

cc (CD containing current TS Bases and TRM):

Mr. K. D. Feintuch
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ATTACHMENT 1

TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

KEWAUNEE POWER STATION TECHNICAL SPECIFICATIONS BASES CHANGES

TS BASES PAGES:
TS B 3.1.5-3
TS B 3.1.6-3
TS B 3.3.1-31
TS B 3.3.1-33
TS B 3.3.2-33
TS B 3.3.3-11
TS B 3.3.3-14
TS B 3.4.3-1 through TS B 3.4.3-4
TS B 3.4.3-6 through TS B 3.4.3-7
TS B 3.4.5-2 through TS B 3.4.5-4
TS B 3.4.6-2
TS B 3.4.6-4
TS B 3.4.10-1
TS B 3.4.10-3
TS B 3.4.12-1 through TS B 3.4.12-9
TS B 3.5.2-2
TS B 3.5.2-5 through TS B 3.5.2-7
TS B 3.6.3-3 through TS B 3.6.3-4
TS B 3.6.3-10
TS B 3.6.6-7
TS B 3.7.2-1
TS B 3.7.2-3
TS B 3.7.5-1 through TS B 3.7.5-4
TS B 3.7.5-7 through TS B 3.7.5-9
TS B 3.8.1-3
TS B 3.8.2-2 through TS B 3.8.2-3
TS B 3.8.4-2
TS B 3.8.6-6

KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

BASES

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks are fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO. This Note only applies while performing SR 3.1.4.2. If performance of the verification activities in SR 3.1.4.2 is paused for more than short periods (beyond that needed to support activities related to completion of testing), then the SR is no longer considered being performed and the allowance provided by the NOTE would no longer apply. During such short periods when testing is paused, personnel performing the SR would normally continue to predominantly remain actively involved with other aspects of the surveillance activity.

ACTIONS

A.1.1, A.1.2, and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths. The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 5). The control bank insertion limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.
LCO	The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.
APPLICABILITY	The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODE 2 with $k_{eff} < 1.0$ and in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES. The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO. This Note only applies while performing SR 3.1.4.2. If performance of the verification activities in SR 3.1.4.2 is paused for more than short periods (beyond that needed to support activities related to completion of testing), then the SR is no longer considered being performed and the allowance provided by the NOTE would no longer apply. During such short periods when testing is paused, personnel performing the SR would normally continue to predominantly remain actively involved with other aspects of the surveillance activity.

BASES

ACTIONS

A Note has been added to 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 3.3.1-1.

In the event a channel's NTSP is found non-conservative with respect to the Allowable Value, or the channel is not functioning as required, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.1-1 are specified (e.g., on a per loop, per RCP, per bus, etc., basis), then the Condition may be entered separately for each loop, RCP, bus, etc., as appropriate.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RPS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the RPIR for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve

BASES

ACTIONS (continued)

be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-14333-P-A (Ref. 8).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 78 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 72 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels > 75% RTP. The 12 hour Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the plant in MODE 3. The 78 hour Completion Time includes 72 hours for channel corrective maintenance, and an additional 6 hours for the MODE reduction as required by Required Action D.3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 8.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using this movable incore detectors once per 12 hours may not be necessary.

BASES

SURVEILLANCE REQUIREMENTS (continued)

protection function. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 10.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a TADOT every 92 days. This test is a check of the Undervoltage RCP Function. The Function is tested up to, and including, the master transfer relay coils. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable TADOT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT. The test is performed in accordance with the SCP. If the actual setting of the channel is found to be conservative with respect to the Allowable Value but is beyond the as-found tolerance band, the channel is OPERABLE. The degraded condition of the channel will be further evaluated during performance of the SR. This evaluation will consist of resetting the channel setpoint to the NTSP (within the allowed tolerance), and evaluating the channel response. If the channel is functioning as required and is expected to pass the next surveillance, then the channel is OPERABLE and can be restored to service at the completion of the surveillance. After the surveillance is completed, the channel as-found condition will be entered into the Corrective Action Program for further evaluation.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable

BASES

ACTIONS

A Note 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 on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function. When the Required Channels in Table 3.3.3-1 are specified (e.g., on a per steam generator, per flow path, per pump, etc., basis), then the Condition may be entered separately for each steam generator, flow path, pump, etc., as appropriate.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies immediate initiation of actions in Specification 5.6.4, which requires a written report to be submitted to the NRC within 14 days. This report discusses the results of the cause of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

C.1

Condition C applies when one or more Functions have two or more inoperable required channels (i.e., two or more channels inoperable in the same Function). Required Action C.1 requires restoring all but one required channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.3.3.3 is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of the Core Exit thermocouple sensors is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. Both the 12 month and 18 month Frequencies are based on operating experience and the 18 month Frequency is consistent with the typical industry refueling cycle.
REFERENCES	1. KW-PLAN-000-RG 1.97. 2. Regulatory Guide 1.97, Revision 3, May 1983. 3. NUREG-0737, Supplement 1, "Clarification of TMI Action Plan Requirements."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

This LCO contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, criticality, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3) and ASME Code, Section XI, Appendix G (Ref. 4). Master curve methodology (Ref. 5) provides an exemption from portions of these requirements.

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 6) and Appendix H of 10 CFR 50 (Ref. 7). The operating P/T limit curves will be

BASES

BACKGROUND (continued)

adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 8).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, an d not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 9), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

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

BASES

LCO

The two elements of this LCO are:

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

b. Limits on the rate of change of temperature (maximum of 100°F/hr for heatup and cooldown).

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.

Figure 3.4.3-1 and Figure 3.4.3-2 are applicable for 52.1 effective full power years (EFPY) of fluence, projected to coincide with the beginning of fuel cycle 46 based on continuous 18 month fuel cycles.

Figure 3.4.3-1 and Figure 3.4.3-2 define limits to assure prevention of nonductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation.

Furthermore, the Figures include margins for instrumentation error and pressure drop (+ 13°F, -30 psi, and -70 psi ΔP).

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 follow:

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

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

BASES

APPLICABILITY

The RCS P/T limits LCO 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 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.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that is within the limits of the applicable Figures (i.e., Figures 3.4.3-1 and 3.4.3-2).

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 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 within 72 hours. 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. 9), 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.

BASES

ACTIONS (continued)

The immediate Completion Time reflects the urgency of initiating action to restore 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 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 prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 9), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

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.

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

BASES

REFERENCES

1. WCAP-16643-NP, "Kewaunee Power Station Heatup and Cooldown Limit Curves for Normal Operation", dated June 2009.
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G.
5. Exemption from the Requirements of 10 CFR 50, Appendix G, Appendix H, and Section 50.61, dated May 1, 2001.
6. ASTM E 185-70 (removal) and ASTM E 185-82 (evaluation).
7. 10 CFR 50, Appendix H.
8. Regulatory Guide 1.99, Revision 2, May 1988.
9. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

BASES

LCO

The purpose of this LCO is to require that two RCS loops be OPERABLE and one RCS loop in operation. The required number of RCS loops in operation ensures that the accident analysis criteria will be met for the postulated accident.

One RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure redundant capability for heat removal.

Note 1 permits all RCPs to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. Another test performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow.

The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. Note 1 permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

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

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

BASES

LCO (continued)

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

Note 2 requires that the secondary side water temperature of each SG be < 100°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 356°F. An indicated temperature of ≤ 356°F must be used to account for instrument uncertainty when applying the LTOP Applicability temperature of ≤ 343°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

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

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2;"
LCO 3.4.6, "RCS Loops - MODE 4;"
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled;"
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled;"
LCO 3.9.3, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1

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

BASES

ACTIONS (continued)

B.1

If restoration for Required Action A.1 is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

If two RCS loops are inoperable or the required RCS loop is not in operation, except as during conditions permitted by Note 1 in the LCO section, the Rod Control System must be placed in a condition incapable of rod withdrawal (e.g., all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets). All operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

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

BASES

LCO (continued)

Note 1 permits all RCPs or RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits the stopping of the pumps in order to perform this test and validate the assumed analysis values. If changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

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

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

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

Note 2 requires that the secondary side water temperature of each SG be < 100°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 356°F (applicable in all of MODE 4). An indicated temperature of ≤ 356°F must be used to account for instrument uncertainty when applying the LTOP Applicability temperature of ≤ 343°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

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

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

BASES

ACTIONS (continued)

B.1 and B.2

If two required loops are inoperable or a required loop is not in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

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

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is $\geq$ 5%. If the SG secondary side narrow range water level is < 5%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is approximately 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 345,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 3 when any RCS cold leg temperature is ≤ 356°F, MODES 4, 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 3% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. 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 American Society of Mechanical Engineers (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.

BASES

APPLICABILITY

In MODES 1, 2, and MODE 3 with both RCS cold leg temperatures > 356°F, OPERABILITY of two valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 is conservatively included, although the safety valves may not be required for protection.

The LCO is not applicable in MODE 3 when any RCS cold leg temperature is ≤ 356°F and in MODES 4 and 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODE 3 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 36 hour exception is based on 18 hour outage time for each of the two valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 3 with any RCS cold leg ≤ 356°F 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. In MODE 3 with any RCS cold leg temperature ≤ 356°F, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 3 with any RCS cold leg ≤ 356°F reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by two pressurizer safety valves.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," provides the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES. The 5°F/hr heatup limit curve in Figure 3.4.3-1 and the isothermal curve (0°F curve) in Figure 3.4.3-2 define the limits to a ssure prevention of nonductile failure applicable to low temperature overpressurization events only. Application of this curve is limited to evaluation of LTOP events whenever one or more of the RCS cold leg temperatures are less than or equal to the LTOP enabling temperature of 356°F.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3 requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the P/T limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all but one safety injection (SI) pump incapable of injection into the RCS and isolating the accumulators. The pressure relief capacity is sufficient to accommodate the input of one SI pump and three charging pumps injecting into the RCS (Reference 4). The pressure relief capacity requires either one RHR System LTOP overpressure relief valve (RHR 33-1) and two RHR suction flow paths or a depressurized RCS and an RCS vent of sufficient size. One RHR System LTOP overpressure relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

BASES

BACKGROUND (continued)

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than one SI pump for makeup in the event of loss of inventory, then a second pump can be made available through manual actions.

The LTOP System for pressure relief consists of an RHR System LTOP overpressure relief valve (RHR 33-1) and two RHR suction flow paths OPERABLE or a depressurized RCS and an RCS vent of sufficient size. An OPERABLE RHR suction flow path is accomplished by maintaining either valves RHR 1A and RHR 2A or RHR 1B and RHR 2B open.

<u>RHR System LTOP Overpressure Relief Valve and RHR Suction Flow Path Requirements</u>

During LTOP MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot legs to the inlets of the RHR pumps. While these valves are open, the RHR System LTOP overpressure relief valve is exposed to the RCS and is able to relieve pressure transients in the RCS.

The RHR System LTOP overpressure relief valve is a spring loaded, bellows type water relief valve with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

<u>RCS Vent Requirements</u>

Once the RCS is depressurized, a vent exposed to containment atmosphere will maintain the RCS at or near containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires removal of a pressurizer safety valve or steam generator manway, or similarly establishing a vent that has an effective flow cross section ≥ 6.4 square inches. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses (Reference 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and in MODE 3 when any RCS cold leg temperature is > 356°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 9 limits. At 356°F and below, overpressure prevention falls to the OPERABLE RHR System LTOP overpressure relief valve or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the RHR System LTOP overpressure relief valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the P/T limit curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RHR relief valve method or the depressurized and vented RCS condition.

Any change to the RCS must be evaluated against the Reference 4 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or energy input transients. The mass input transient assumes an inadvertent safety injection (SI) pump start with two RHR and two reactor coolant pumps operating. The energy input transient assumes an initial reactor coolant pump start with steam generator to RCS temperature difference of 100°F and two RHR pumps ope rating.

During the LTOP MODES, to ensure that unanalyzed mass and energy input transients do not occur, a reactor coolant pump shall not be started with one or more RCS cold leg temperatures ≤ 356°F unless the secondary water temperature of each steam generator is < 100°F above each RCS cold leg temperature.

The Reference 4 analyses demonstrate that either the RHR System LTOP overpressure relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when only one SI pump and three charging pumps are actuated. Thus, the LCO allows only one SI pump OPERABLE during the LTOP MODES. Since neither the RHR System LTOP overpressure relief valve nor the RCS vent can handle the pressure transient from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators' isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in Figure 3.4.3-1 and Figure 3.4.3-2. Administrative controls provide for isolation of the accumulators as needed to prevent inadvertent injection when RCS pressure is ≤ 775 psig.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

ASME Section XI, Appendix G (Ref. 8) established the temperature of LTOP Applicability at 343°F (i.e., the greater of RT_{NDT} + 50°F or 200°F). An indicated temperature of ≤ 356°F must be used to account for instrument uncertainty when applying the LTOP Applicability temperature of ≤ 343°F.

RHR System LTOP Overpressure Relief Valve Performance

The RHR System LTOP overpressure relief valve does not have variable pressure and temperature lift setpoints. Analyses must show that the RHR System LTOP overpressure relief valve with a lift setting ≤ 500 psig will pass flow greater than that required for the limiting LTOP transient while maintaining RCS pressure less than the P/T limit curve. The RHR System LTOP overpressure relief valve set pressure specified includes consideration for the opening setpoint tolerance of ± 3% (± 15 psig) as defined in ASME Boiler and Pressure Vessel Code, Section III, Subsection NC: Class 2 Components for Safety Relief Valves (Ref. 3). The analysis of pressure transient conditions has demonstrated acceptable relieving capability at the upper tolerance limit of 515 psig.

Although the RHR System LTOP overpressure relief valve may itself meet single failure criteria, its inclusion and location within the RHR System does not allow it to meet single failure criteria when spurious RHR suction isolation valve closure is postulated. Also, as the RCS P/T limits are decreased to reflect the loss of toughness in the reactor vessel materials due to neutron embrittlement, the RHR System LTOP overpressure relief valve must be analyzed to still accommodate the LTOP transients.

The RHR System LTOP overpressure relief valve is considered an active component.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 6.4 square inches (equivalent to that of the LTOP overpressure relief valve) is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transients for the LTOP configuration. The licensing basis mass input transient assumes an inadvertent SI pump start with two RHR pumps and two reactor coolant pumps (RCPs) operating. The licensing basis energy input transient assumes an initial RCP start with a steam generator to RCS temperature differential of 100°F and two RHR pumps operating.

BASES

APPLICABLE SAFETY ANALYSES (continued)	The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance. The RCS vent is passive and is not subject to active failure. The LTOP System satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that the LTOP System is OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient. To limit the coolant input capability, the LCO requires that a maximum of one SI pump be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized (when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in Figure 3.4.3-1 and Figure 3.4.3-2). The LCO is modified by two Notes. Note 1 states that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions. Note 2 requires that the secondary side water temperature of each SG be $\leq$ 100°F above each of the RCS cold leg temperatures be fore the start of an RCP with any RCS cold leg temperature $\leq$ 356°F. An indicated temperature of $\leq$ 356°F must be used to account for instrument uncertainty when applying the LTOP Applicability temperature of $\leq$ 343°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started. The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

BASES

LCO (continued)

a. The OPERABLE RHR System LTOP overpressure relief valve and two RHR suction flow paths OPERABLE;

The RHR System LTOP overpressure relief valve (RHR 33-1) is required to be OPERABLE for LTOP. In addition, the RHR shall be aligned to the RCS by maintaining both RHR suction flow paths OPERABLE. Valves RHR 1A, RHR 1B, RHR 2A, and RHR 2B must be open for the suction flow paths to be OPERABLE.

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when open with an area of ≥ 6.4 square inches.

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

APPLICABILITY

This LCO is applicable in MODE 3 when any indicated RCS cold leg temperature is ≤ 356°F, in MODES 4, 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 356°F. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and MODE 3 (with both RCS cold leg temperatures > 356°F).

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

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP System. There is an increased risk associated with entering MODE 4 from MODE 5, or entering MODE 3 from MODE 4, with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

BASES

ACTIONS (continued)

A.1

With two SI pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

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

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > 356°F, an accumulator pressure of 775 psig cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit from Figure 3.4.3-1 and Figure 3.4.3-2 also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

D.1 and D.2

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Reference 5). Thus, with one of the two RHR suction flow paths inoperable, action must be taken to immediately verify that the suction valves in the other RHR suction flow path are locked open with the motive power removed. Additionally, the inoperable RHR suction flow path must be restored to OPERABLE status. The Completion Time to restore the RHR suction flow path to OPERABLE status is 5 days.

The Completion Time for the inoperable RHR suction flow path represents a reasonable time to investigate and repair the RHR suction flow path without exposure to a lengthy period with only one OPERABLE RHR suction flow path to protect against overpressure events and is acceptable as described in Reference 6.

BASES

ACTIONS (continued)

E.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RHR suction flow paths are inoperable;

b. The Required Action and associated Completion Time of Condition A, C, or D is not met; or

c. The RHR System LTOP overpressure relief valve is inoperable.

The vent must be sized ≥ 6.4 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers 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. The Completion Time was also approved in Amendment 108 (Ref. 6).

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of one SI pump is verified incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out.

The SI pump is rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.3

Each required RHR suction valve shall be demonstrated OPERABLE by verifying the valve is open and by testing it in accordance with the Inservice Testing Program. This Surveillance is only required to be performed if the RHR suction relief valve is being used to meet this LCO.

The RHR suction valves are verified to be opened every 12 hours. The Frequency is considered adequate in view of other administrative controls such as valve status indications available to the operator in the control room that verify the RHR suction valves remain open.

The ASME Code (Ref. 7), test per Inservice Testing Program verifies OPERABILITY by proving proper relief valve mechanical motion and by measuring and, if required, adjusting the lift setpoint.

SR 3.4.12.4

The RCS vent of ≥ 6.4 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked (valves that are sealed or secured in the open position are considered "locked" in this context); or

b. Once every 31 days for other vent path(s) (e.g., a vent valve that is locked, sealed, or secured in position). A removed pressurizer safety valve or open manway also fits this category.

The passive vent path arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

BASES

BACKGROUND (continued)

supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Separate piping supplies each subsystem and each train within the subsystem. The RHR pumps deliver through two nozzles that penetrate the reactor vessel and core barrel. The SI pumps deliver into two separate headers which are cross connected so that either pump is capable of providing flow to the RCS cold legs or reactor vessel injection nozzles. One header supplies the cold legs and the other header supplies the reactor vessel. The header to the reactor vessel (normally isolated) divides into two separate injection lines which connect to the lines from the RHR pumps and supply the two reactor vessel nozzles. These lines are normally isolated. The header to the cold legs divides into two injection lines connected to the cold legs of the RCS. Manual valves (SI-10A and SI-10B) in the safety injection lines to the RCS cold legs are positioned and locked to the correct throttle position to ensure proper flow and balance of flow of each loop. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The recirculation flow goes from the discharge of the RHR pump through the RHR heat exchanger and then into the reactor via either a low-head injection path or a high-head injection path via a safety injection pump. The high-head injection paths are provided in the event of a small break in which the pressure in the RCS is higher than the shutoff head of the RHR pump.

The safety injection subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

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

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start

BASES

LCO (continued)	pumps). In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS cold legs or vessel. The flow path for each train must maintain its designed independence to ensure that no single active failure can disable both ECCS trains. As indicated in Note 1, an SI train may be considered OPERABLE for up to 1 hour when being used to fill an SI accumulator, provided the other SI train is OPERABLE. As indicated in Note 2, operation in MODE 3 with an SI pump made incapable of injecting in order to facilitate entry into or exit from the Applicability of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System", is necessary with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that an SI pump be rendered incapable of injecting at and below the LTOP arming temperature. Since this temperature is near the MODE 3 boundary temperature, time is needed to make a pump incapable of injecting prior to entering the LTOP Applicability, and provide time to restore the inoperable pump to OPERABLE status on exiting the LTOP Applicability. Note 2 provides four hours for this activity, or until both RCS cold leg temperatures exceed 381°F (Low Temperature O verpressure Protection (LTOP) arming temperature plus 25°F), whi chever occurs first.
APPLICABILITY	In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a 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. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis. This LCO is only applicable in MODE 3 and above. Below MODE 3, certain SI signals are manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown." In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low.

BASES

ACTIONS

A.1

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

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

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one active 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. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable. However, procedural guidance must be provided to use two different components, each in a different train, to meet 100% of ECCS flow equivalent (Ref. 7).

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

B.1 and B.2

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

C.1

Condition A is applicable with one or more trains inoperable. The allowed Completion Time is based on the assumption that at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. However, procedural guidance must be provided to use two different

BASES

ACTIONS (continued)	components, each in a different train, to meet 100% of ECCS flow equivalent (Ref. 7). With less than 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the facility is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

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

SR 3.5.2.2

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

SR 3.5.2.3

Not used.

BASES

APPLICABLE SAFETY ANALYSES (continued)

lines could be isolated even if a single active failure occurred. The containment purge and vent isolation valves are air operated spring closed. The valves fail closed on a loss of power or instrument air.

The purge and vent isolation valves may be unable to close in the environment following a LOCA. Therefore, each of the purge and vent isolation valves is required to remain sealed closed during MODES 1, 2, 3, and 4.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch purge and vent isolation valves must be maintained sealed closed. The valves covered by this LCO are listed in the USAR (Ref. 2) and the associated valve stroke times are listed in the IST Program Plan implementing procedures. However, the main steam isolation valves and main feedwater isolation valves are not covered by this LCO. Requirements for these valves are provided in LCO 3.7.2, "Main Steam Isolation Valves (MSIVs)," and LCO 3.7.3, "Main Feedwater Isolation Valves (MFIVs), Main Feedwater Regulating Valves (MFRVs), and MFRV Bypass Valves." ITS 3.6.9, Vacuum Relief Valves, should be reviewed for applicability if the vacuum breakers are inoperable such that the vacuum relief function is affected.

The normally closed isolation valves are considered OPERABLE when manual valves are closed and automatic valves are de-activated and secured in their closed position. Normally open manual isolation valves are considered OPERABLE when the valve is closed or capable of being closed. Blind flanges being in place or an intact closed system pressure boundary, either inside or outside containment, can act as one of two barriers for the penetration and functions in lieu of a valve for one or both penetration barrier(s). These passive isolation valves/devices are those listed in Reference 2.

Penetrations which extend into the auxiliary building special ventilation zone and penetrations which are exterior to both the shield building and the auxiliary building special ventilation zone must meet additional leakage rate requirements (i.e., combined bypass leakage rate limits).

BASES

LCO (continued)

The other containment isolation valve leakage rates are addressed by LCO 3.6.1, "Containment," as Type C testing.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a release of radioactive material to containment could occur. In MODES 5 and 6, the probability and consequences of a release are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, except for 36 inch purge and vent valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous communication with the control room (e.g., radio, PCS phone, plant announcing system). In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge and vent line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event the isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

SURVEILLANCE REQUIREMENTS (continued)

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation times are provided in the IST Program Plan implementing procedures and the Frequency of this SR is in accordance with the Inservice Testing Program.

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

This SR ensures that the combined bypass leakage rate of all penetrations which extend into the auxiliary building special ventilation zone and all penetrations which are exterior to both the shield building and the auxiliary building special ventilation zone is less than or equal to the specified leakage rates. This provides assurance that the assumptions in the safety analysis are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve,

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.2

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

SR 3.6.6.3

Verifying that each containment cooling train service water cooling flow rate to each cooling unit provides assurance that the assumed post-accident heat load can be removed (Ref. 6). The assumed flow rate for containment fan coil units A, B, C, and D is 800 gpm. For the flow test to be performed at power, test alignment will only address closing one of the service water system header isolation valves (cross-connect valves SW-3A or SW-3B), bypass shroud cooling and not establish post-accident cooling flows to other ESF components. The frequency was developed considering the known reliability of the cooling water system, the two train redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by the ASME Code (Ref. 7). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The frequency of the SR is in accordance with the inservice testing program.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a main steam line break (MSLB). MSIV closure terminates flow from the unaffected (intact) steam generator.

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

The MSIVs close on a main steam isolation signal. Individual MSIV closures will occur upon receipt of a Safety Injection concurrent with High-High Steam Flow signals or a Safety Injection, a High Steam Flow, and a Lo-Lo T_{avg} signal. Both MSIVs will close upon receipt of a Containment High-High pressure signal. The MSIVs fail as is on loss of control power and closed on loss of actuation power (i.e., air). The MSIVs may also be actuated manually.

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

In addition to the fast-closing stop valve, each steam line has a downstream non-return check valve (NRCV). The four valves (one MSIV and one NRCV in each of the two lines) prevent blowdown of more than one steam generator for any break location even if one valve fails to close.

A description of the MSIVs is found in the USAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment integrity analysis for the large steam line break (SLB) inside containment and the accident analysis of the SLB events as discussed in the USAR, Section 14.2.5 (Ref. 2). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

BASES

APPLICABLE SAFETY ANALYSES (continued)

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

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

LCO

This LCO requires that the MSIV in both steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 50.67 (Ref. 3) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed and de-activated, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally the MSIVs are closed, and the steam generator energy is low.

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

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 24 hours. Some repairs to the MSIV can be made with the unit hot. The 24 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 24 hour Completion Time is consistent with that normally allowed for containment isolation valves that isolate a non-closed system penetrating containment.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction through a common suction line from the two condensate storage tanks (CSTs) (LCO 3.7.6, "Condensate Storage Tanks (CSTs)") and pump to the steam generator secondary side via separate and independent connections to the main feedwater (MFW) piping inside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1, "Main Steam Safety Valves (MSSVs)") or steam generator power operated relief valves (LCO 3.7.4, "Steam Generator (SG) Power Operated Relief Valves (PORVs)"). If the main condenser is available, steam may be released via the steam bypass valves and recirculated to the CST.

The AFW System consists of two motor driven AFW (MDAFW) pumps and one steam turbine driven AFW (TDAFW) pump configured into three trains. Any two AFW pumps provide greater than 100% of the AFW flow requirements, as assumed in the accident analyses. Each pump is equipped with a recirculation line to prevent pump operation against a closed system.

Each MDAFW pump is powered from an independent Class 1E safeguard bus. Each MDAFW pump has a cavitating venturi at its discharge to protect the pump from runout conditions. Immediately downstream of each cavitating venturi, a branch connection (cross connect) permits each MDAFW pump to supply either or both steam generators. The supply line from each MDAFW pump to each steam generator has a remote manual flow control valve, check valve, and manual isolation valve to permit flow control.

The TDAFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the TDAFW pump. The pump has a cavitating venturi at its discharge to protect the pump from run out conditions. Immediately downstream of this cavitating venturi, a branch connection permits the TDAFW pump to supply either or both steam generators. The supply line from the TDAFW pump to each steam generator has a remote manual flow control valve, check valve, and manual isolation valve to permit flow control.

BASES

BACKGROUND (continued)

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the self-actuated safety valves.

The AFW System actuates automatically on steam generator water level - low-low by the ESFAS (LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation"). The system also actuates on loss of offsite power, safety injection, and trip of all MFW pumps.

The AFW System is discussed in the USAR, Section 6.6 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest main steam safety valve set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation. In MODE 4, when a steam generator is relied upon for decay heat removal, one AFW train with a MDAFW pump is required to be capable of supplying required flow to each steam generator being relied upon.

The limiting Design Basis Accident (DBA) for the AFW System is the loss of normal feedwater (LONF) event. The LONF event is limiting for AFW System performance requirements due to the requirement that the pressurizer not go water solid during the transient. The analysis of the LONF event has been performed assuming AFW flow is available 60 seconds from event initiation with acceptable results. Two AFW trains are required to meet the AFW flow requirements.

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition to its accident mitigation function, the energy and mass addition capability of the AFW System is also considered with respect to Main Steam Line Break (MSLB) within containment. For MSLBs within containment, flow from all three AFW pumps is assumed until operations can isolate the flow 10 minutes from event initiation by tripping the AFW pumps or by closing the respective pump discharge flow path(s). The isolation of the AFW System limits the energy and mass addition so that containment remains within design limits. Furthermore, flow from only one AFW train is actually required to meet the AFW flow requirement to remove decay heat.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of voltage on 4kV Bus 1 and Bus 2. AC power operated throttle valves are provided in the two steam generator supply lines from each MDAFW pump to control the AFW flow to each steam generator. The discharge of the TDAFW pump is cross connected to supply each steam generator. Motor operated valves (AFW-10A and AFW-10B) are DC motor operated throttle valves and are used to control the AFW flow to each steam generator from the TDAFW pump.

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

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary.

Three independent AFW trains are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW system is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. AFW supply is met by condensate storage tank OPERABILITY and the capability of taking suction from the service water system. This requires that the two MDAFW pumps be OPERABLE and capable of supplying AFW to both steam generators. The TDAFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to both of the steam generators. The piping, valves, instrumentation, and

BASES

LCO (continued)

controls in the required flow paths also are required to be OPERABLE.

The AFW pumps' low suction pressure trip channels shall be FUNCTIONAL as required by TRM 8.3.3.

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

APPLICABILITY

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

In MODE 4 the AFW System may be used for heat removal via the steam generators.

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

ACTIONS

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

A.1

If the turbine driven AFW train is inoperable due to one inoperable steam supply, or if the turbine driven train is inoperable for any reason while in MODE 3 immediately following refueling, action must be taken to restore the inoperable equipment to an OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

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

The SR is modified by a Note (Note 1) that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Alignment and operation for steam generator load control includes placing the AFW pump control switches in the control room in the "pull out" position, and throttling or closing AFW-2A, AFW-201A, AFW-2B, AFW-201B, AFW-10A, and/or AFW-10B. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System, OPERABILITY (i.e., the intended safety function) continues to be maintained.

This SR is modified by a second Note (Note 2) that states one of the AFW header cross-tie valves is allowed to be closed to perform testing of the motor driven AFW pump for up to 4 hours and the turbine driven AFW train may be considered OPERABLE, provided the closed cross-tie valve is capable of being remotely (i.e., from the control room) realigned to the open position. This exception allows the AFW System to be out of its normal standby alignment and the turbine driven AFW train temporarily incapable of automatic injection to both SGs without declaring the turbine driven AFW train inoperable. This is acceptable since the valves are capable of remote manual operation from the control room. Modification of the AFW system (Ref. 3) resulted in the allowance provided by Note 2 no longer being needed. Although Note 2 continues to allow it, closure of one of the header cross-tie valves is not needed for flow testing of AFW.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the ASME Code (Ref 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

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

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

The SR is modified by a Note that states one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Alignment and operation for steam generator load control includes placing the AFW pump control switches in the control room in the "pull out" position, and throttling or closing AFW-2A, AFW-201A, AFW-2B, AFW-201B, AFW-10A, and/or AFW-10B. Since AFW may be used during startup,

BASES

SURVEILLANCE REQUIREMENTS (continued)

shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System, OPERABILITY (i.e., the intended safety function) continues to be maintained.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In MODE 4, the required pump is already operating and the auto start function is not required. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. The Note 2 states that one or more AFW trains may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually (i.e., remotely or locally, as appropriate) realigned to the AFW mode of operation, provided it is not otherwise inoperable. This exception allows the system to be out of its normal standby alignment and temporarily incapable of automatic initiation without declaring the train(s) inoperable. Alignment and operation for steam generator load control includes placing the AFW pump control switches in the control room in the "pull out" position, and throttling or closing AFW-2A, AFW-201A, AFW-2B, AFW-201B, AFW-10A, and/or AFW-10B. Since AFW may be used during startup, shutdown, hot standby operations, and hot shutdown operations for steam generator level control, and these manual operations are an accepted function of the AFW System. OPERABILITY (i.e., the intended safety function) continues to be maintained.

REFERENCES

1. USAR, Section 6.6.
2. ASME Code for Operation and Maintenance of Nuclear Power Plants 1998 Edition through OMB 2000 Addenda.
3. DCR 3609-2, AFW Flow Control.

BASES

LCO (continued)

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

One qualified offsite circuit consists of the 138/21 kV Reserve Auxiliary Transformer (RAT) Supply Transformer, powered by the 138 kV portion of the substation, to the 20/4.16 kV RAT and normally supplying power to Bus 1-6. The other qualified offsite circuit consists of the 138/13.8 kV TAT Supply Transformer, powered by the 138 kV portion of the substation, to the 13.2/4.16 kV Tertiary Auxiliary Transformer (TAT) and normally supplying power to Bus 1-5. The substation transformers that supply the reserve and tertiary auxiliary transformers are each provided with a load tap changer. These load tap changers provide voltage regulation in the event of changing transmission system voltage. The load tap changers can be operated in manual or automatic mode.

The 138 kV and 345 kV portions of the substation are interconnected by two 345/138 kV Auto Transformers. The offsite circuits also include the supply breakers to buses 1-5 and 1-6. While each circuit has connections to each 4.16 kV ESF bus, each offsite circuit is only required to be capable of supplying one of the 4.16 kV ESF buses at a time.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to reject full load.

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

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

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with fast transfer capability for one ESF bus to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE fast transfer interlock mechanisms to at least one ESF bus to support OPERABILITY of that circuit. In addition, day tanks fuel oil level and fuel oil transfer system requirements must be met for each DG.

BASES

APPLICABLE SAFETY ANALYSES (continued)

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

This LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

AC Sources - Shutdown satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with a distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es).

One qualified offsite circuit consists of the 138/21 kV Reserve Auxiliary Transformer (RAT) Supply Transformer, powered by the 138 kV portion of the substation, to the 20/4.16 kV RAT and normally supplying power to Bus 1-6. The other qualified offsite circuit consists of the 138/13.8 kV TAT Supply Transformer, powered by the 138 kV portion of the substation, to the 13.2/4.16 kV Tertiary Auxiliary Transformer (TAT) and normally supplying power to Bus 1-5. The substation transformers that supply the reserve and tertiary auxiliary transformers are each provided with a load tap changer. These load tap changers provide voltage regulation in the event of changing transmission system voltage. The load tap changers can be operated in manual or automatic mode.

A third qualified offsite circuit available for connection to the ESF buses consists of the 20/4.16 kV Main Auxiliary Transformer, powered by the

BASES

LCO (continued)

345 kV portion of the substation through the 345/20 kV Main Transformers. This third circuit is available for connecting offsite power to the ESF buses when the reactor is shutdown and the main generator links are removed. It is normally not relied on except when one or both of the other circuits are unavailable. To ensure circuit reliability and prevent unnecessary opening of the main generator output breaker, protective trips associated with main generator operation are disabled when supplying offsite power through this circuit.

The 138 kV and 345 kV portions of the substation are interconnected by two 345/138 kV Auto Transformers. The offsite circuits also include the supply breakers to buses 1-5 and 1-6. While each circuit has connections to each 4.16 kV bus, each circuit is only required to be capable of supplying one of the 4.16 kV buses at a time. However, if only one offsite circuit is used to meet the LCO requirement, then it must be supplying both buses 1-5 and 1-6.

The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby at ambient conditions.

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

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

BASES

BACKGROUND (continued)

Each battery has adequate storage capacity to meet the duty cycle(s) discussed in the USAR, Chapter 8 (Ref 3). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for Train A and Train B DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The minimum design voltage limits are 110 V for Battery BRA-101 and 112 V for Battery BRB-101.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. Optimal long term performance is obtained by maintaining a float voltage 2.19 to 2.29 Volts per cell (Vpc). This provides adequate over-potential, which limits the formation of lead sulfate and self discharge. The nominal float voltage of 2.24 Vpc corresponds to a total float voltage output of 132 V for a 59 cell battery as discussed in the USAR, Chapter 8 (Ref. 3).

Each Train A and Train B DC electrical power subsystem battery charger has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each of the three safeguard battery chargers has been sized to recharge either of the partially discharged safeguard batteries within 24 hours, while carrying its normal load. Partially discharged is defined as any condition between the battery charge condition after 8 hours of discharge (not less than 105 V) and nominal 125 V.

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provide the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 1).

SR 3.8.6.6

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.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

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.

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

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1) and IEEE-485 (Ref. 4). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's

ATTACHMENT 2

TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

KEWAUNEE POWER STATION TECHNICAL REQUIREMENTS MANUAL CHANGES

TRM PAGES:
TRM 8.3.3 Rev. 1, pages 8.3.3-1 through 8.3.3-5
TRM 8.3.5 Rev. 1, pages 8.3.5-1 through 8.3.5-6
TRM 8.3.7 Rev. 1, pages 8.3.7-1 through 8.3.7-5
TRM 8.5.1 Rev. 1, pages 8.5.1-1 through 8.5.1-3
TRM 8.7.2 Rev. 1, pages 8.7.2-1 through 8.7.2-5
TRM 8.8.3 Rev. 0, pages 8.8.3-1 through 8.8.3-7
TRM 8.9.4 Rev. 1, pages 8.9.4-1 through 8.9.4-3

KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

8.3 INSTRUMENTATION

8.3.3 Auxiliary Feedwater (AFW) Pump Low Suction Pressure Trip Channels

TNC 8.3.3 One low suction pressure trip channel shall be FUNCTIONAL for each AFW pump.

APPLICABILITY: Whenever the associated AFW pump is required to be OPERABLE.

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. AFW pump low suction pressure trip channel on one or more AFW pumps NonFUNCTIONAL.	A.1 Declare associated AFW train(s) INOPERABLE and apply requirements of Technical Specification (TS) 3.7.5.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
	--------------------------------NOTE------------------------ Verification of relay setpoints is not required. ---	
TVR 8.3.3.1	Perform CHANNEL FUNCTIONAL TEST on each AFW pump low suction pressure trip channel.	92 days
TVR 8.3.3.2	Deleted	
TVR 8.3.3.3	Perform CHANNEL CALIBRATION on each AFW pump low suction pressure trip channel.	18 months
TVR 8.3.3.4	Deleted	

BASES

BACKGROUND

AFW pump low suction pressure trip protects pump internals from damage that could result from loss of the required net positive suction head (NPSH), which could be caused by loss of the normal water supply from the condensate storage tanks (CSTs) following a tornado or seismic event.

Three pressure switches (one per pump) are located on the AFW pump suction line from the CST. The set point of each pressure switch is designed to preclude pump operation with sub-atmospheric pressure at the AFW pump suction. A low-pressure signal sensed by any one of the switches will cause the associated AFW pump to trip. Operator action is required to bypass the trip circuit or align to the service water source and restart the associated AFW pump. Service water alignment and restart of the AFW pumps ensures an adequate supply of water to maintain at least one of the steam generators (SGs) as the heat sink for reactor decay heat and sensible heat removal.

A cavitating venturi is installed in the discharge of each AFW pump. At high SG pressures, the venturi operates in resistance mode as a flow control element in conjunction with the AFW pump discharge throttle valves. For low SG pressures (associated with accidents or transients) flow through the venturis cavitates and limits flow through the AFW pumps precluding pump runout. At the maximum possible flow rate thru the venturi, the pump's required NPSH is maintained less than atmospheric pressure. Since the AFW pump low suction pressure trips are set to stop pump operation prior to suction pressure dropping below atmospheric, margin to required NPSH continues to be maintained.

The requirement for AFW pump low suction pressure trip was relocated from the previous Custom TS during the conversion to Improved TS. In License Amendment 183 (Reference 1), the NRC approved a four hour allowance to defer applying the AFW TS requirements for the condition of one low suction pressure trip channel inoperable. This amendment stipulated that when only a single trip channel was inoperable, the AFW pump associated with that trip channel was allowed to be considered OPERABLE for up to four hours, provided the AFW train was otherwise OPERABLE. In License Amendment 207 (Reference 2), the NRC approved relocating this 4 hour allowance to the TRM. However, since this trip function is required for AFW pump OPERABILITY, TS LCO 3.7.5 is not met with an AFW pump low suction pressure trip channel NonFUNCTIONAL. Therefore, this relocated allowance is not applicable.

BASES

TNC and APPLICABILITY

AFW pump low suction pressure trip channels (one per pump) support OPERABILITY of the AFW system (Reference 3) by providing automatic protection for the pumps. The low pressure trip is necessary in order to prevent damage to the AFW pumps if the normal water supply (from the CSTs) is lost following a tornado or seismic event. Therefore each channel must be FUNCTIONAL whenever its associated (supported) AFW train is required to be OPERABLE.

One low suction pressure trip channel must be FUNCTIONAL for each AFW pump whenever its supported AFW pump is required to be OPERABLE per TS 3.7.5 (Reference 3).

CONTINGENCY MEASURES

A.1

Loss of a pressure trip channel unacceptably degrades AFW pump protection capability. If one or more AFW pump low suction pressure trip channels are NonFUNCTIONAL, the associated AFW train(s) shall immediately be declared INOPERABLE and the applicable requirements of TS 3.7.5 applied. Contingency Measure A.1 thereby limits the time that a channel may be removed from service.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.3.3.1

A CHANNEL FUNCTIONAL TEST is required to be performed on each AFW pump's low suction pressure trip channel every 92 days. Verification of relay setpoints is not required to be performed during the conduct of this test.

TVR 8.3.3.3

A CHANNEL CALIBRATION is required to be performed on each AFW pump's low suction pressure trip channel every 18 months.

BASES

REFERENCES

1. License Amendment 183, "Kewaunee Nuclear Power Plant – Issuance of Amendment Re: Auxiliary Feedwater System (TAC No. MC6916", dated June 20, 2005.
2. License Amendment 207, "Kewaunee Power Station (KPS) – Issuance of Amendment for the Conversion to the Improved Technical Specifications with Beyond Scope Issues (TAC Nos. ME2139, ME2419, ME2420, ME2421, ME3122, ME3460, and ME3544)", dated February 2, 2011.
3. TS 3.7.5, AFW System.

8.3 INSTRUMENTATION

8.3.5 Post Accident Monitoring (PAM) Instrumentation

TNC 8.3.5 The PAM instrumentation for each Function in Table 8.3.5-1 shall be FUNCTIONAL.

APPLICABILITY: MODES 1 and 2.

CONTINGENCY MEASURES

-----NOTE-----
Separate Condition entry is allowed for each Function.

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. One or more Functions with one required channel NonFUNCTIONAL.	A.1 Restore required channel to FUNCTIONAL status.	14 days
B. One or more Functions with two required channels NonFUNCTIONAL.	B.1 Restore required channels to FUNCTIONAL status.	72 hours
C. Required CONTINGENCY MEASURES and associated Restoration Time of Nonconformance A or B not met.	C.1 Enter TNC 7.5.3.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

--NOTE--
These TVRs apply to each PAM instrumentation Function in Table 8.3.5-1.

	VERIFICATION	FREQUENCY
TVR 8.3.5.1	---------------------------------NOTE--------------------------- Verification of auxiliary feedwater (AFW) flow rate indicator is only required during unit startup and shutdown. -- Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
TVR 8.3.5.2	Perform CHANNEL CALIBRATION.	18 months

Table 8.3.5-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS
1. AFW Flow Rate indication	1 per SG
2. Pressurizer Power Operated Relief Valve Position (One Common Channel Temperature, One Channel Limit Switch per Valve)	2 per valve
3. Pressurizer Power Operated Relief Block Valve Position (One Common Channel Temperature, One Channel Limit Switch per Valve)	2 per valve
4. Pressurizer Safety Valve Position (One Channel Temperature, and One Acoustic Sensor)	2 per valve

BASES

BACKGROUND	The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. Post Accident Monitoring Instruments are divided into one or more of five (5) types of variables (A, B, C, D, & E). Type A variables are those variables to be monitored that provide the primary information required to permit the control room operators to take the specified manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety function for design basis accident events. Types B, C, D, and E are variables for following the course of an accident and are to be used (1) to determine if the plant is responding to the safety measures in operation and (2) to inform the operator of the necessity for unplanned actions to mitigate the consequences of an accident. Further definition of Type B, C, D, and E variables can be found in the KPS RG 1.97 Accident Monitoring Instrumentation Plan (Reference 1). The FUNCTIONALITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident. Only those instruments monitoring Type A and Category 1 variables are required to be included in Technical Specifications (TS). The instruments in this Technical Requirement do not meet the criteria for inclusion into TS. The requirements for PAM instrumentation that did not meet Type A or Category 1 variables were relocated from the previous Custom TS Table 3.5-6, "Accident Monitoring Instrumentation Operating Conditions for Indication," during the conversion to Improved TS in License Amendment 207 (Reference 2). That conversion also deleted the previous requirement for the unit to be shutdown if a required channel was nonfunctional and not restored within the allowed restoration time.
TNC and APPLICABILITY	The PAM instrumentation TNC is applicable in MODES 1 and 2. The PAM instrumentation TNC provides FUNCTIONALITY requirements for the monitors listed in Table 8.3.5-1 (Regulatory Guide 1.97 monitors other than Type A or Category 1), which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. The FUNCTIONALITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident.

BASES

CONTINGENCY MEASURES

A Note has been added in the CONTINGENCY MEASURES to clarify the application of Restoration Time rules. The conditions of this requirement may be entered independently for each Function listed on Table 8.3.5-1. The Restoration Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the condition was entered for that Function. When the Required Channels in Table 8.3.5-1 are specified (e.g., on a per steam generator, per valve, etc., basis), then the condition may be entered separately for each steam generator, valve, etc., as appropriate.

A.1

Nonconformance A applies when one or more Functions have one required channel that is NonFUNCTIONAL. CONTINGENCY MEASURE A.1 requires restoring the NonFUNCTIONAL channel to FUNCTIONAL status within 14 days.

B.1

Nonconformance B applies when one or more Functions have two NonFUNCTIONAL required channels (i.e., two channels NonFUNCTIONAL in the same Function). CONTINGENCY MEASURE B.1 requires restoring all but one required channel in the Function(s) to FUNCTIONAL status within 72 hours.

C.1

Nonconformance C applies when the CONTINGENCY MEASURE and associated completion time of Nonconformance A or B is not met. CONTINGENCY MEASURE C.1 requires initiating the action specified in TNC 7.5.3 immediately. Each time a nonfunctional channel has not met the CONTINGENCY MEASURE of either Nonconformance A or B, and the associated completion time has expired, Condition C is entered for that channel and provides for transition to TNC 7.5.3.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.3.5.1

This verification is modified by a Note that alters the frequency requirement for checking the AFW flow rate indicator. Rather than at the normally specified 31 day interval, AFW flow rate indication is required to be checked during each startup and shutdown of the unit (unless it was performed in the previous 31 days).

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, 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. If the channels are within the criteria, it is an indication that the channels are FUNCTIONAL.

As specified in the TVR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the TNC required channels.

TVR 8.3.5.2

A CHANNEL CALIBRATION is performed every 18 months for all Functions, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy.

REFERENCES

1. KW-PLAN-000-RG 1.97, "Regulatory Guide 1.97 Accident Monitoring Instrumentation Plan".
2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 207 to Facility Operating License No. DPR-43, Dominion Energy Kewaunee, Inc., Kewaunee Power Station, Docket No. 50-305, dated February 2, 2011.

8.3 INSTRUMENTATION

8.3.7 Explosive Gas Monitoring System

TNC 8.3.7 The Waste Gas Analyzer (WGA) shall be FUNCTIONAL and aligned to monitor the in service Waste Gas Decay Tank (WGDT) such that its oxygen concentration does not exceed 4% by volume.

APPLICABILITY: Whenever a WGDT is in service.

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. WGA NonFUNCTIONAL. OR WGA not aligned to in service WGDT.	A.1 Take and analyze samples from in service WGDT.	Once per 4 hours during degassing of primary system (other than normal gas stripping of the letdown flow) OR Once per 24 hours during normal power operation
B. Oxygen concentration in the in service WGDT > 4% by volume.	B.1 Suspend additions of waste gas to affected WGDT. AND B.2 Initiate action to reduce the oxygen concentration to < 4% by volume.	Immediately Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
	---NOTE--- Test consists of an analysis of a known gas standard. ---	
TVR 8.3.7.1	Perform FUNCTIONAL TEST on Waste Gas Analyzer.	31 days
	---NOTE--- Test consists of an analysis of a known gas standard. ---	
TVR 8.3.7.2	Perform CHANNEL CALIBRATION.	92 days

BASES

BACKGROUND

The Explosive Gas Monitoring System utilizes an inline Waste Gas Analyzer (WGA) to monitor the in service Waste Gas Decay Tank (WGDT) on a continuous basis. Grab sample analysis of the in service WGDT can be accomplished by obtaining a sample locally from the in service gas decay tank or from a sample point located on the WGA. Grab samples are analyzed with chemistry laboratory analytical equipment. If inline or grab sample analysis indicates an explosive mixture, actions will be taken to reduce the oxygen concentration as soon as possible.

The WGA provides a method for monitoring the concentrations of potentially explosive gas mixtures in the waste gas holdup system (Reference 5). An explosive gas mixture consists of a hydrogen gas concentration above the lower flammability limit of 4% AND an oxygen gas concentration above 4%. Technical Specification 5.5.10 requires a program that provides controls for potentially explosive gas mixtures in the gaseous radioactive waste disposal system (Reference 6).

The WGA has alarm capability that will alert operations personnel of oxygen concentrations approaching an explosive mixture and is set to 2% oxygen by volume. The 2% alarm setpoint on the WGA is based on the 4% oxygen concentration required for flammability. This allows for a 100% safety margin in the setpoint. The WGA alarms in the control room and is locally monitored at least daily. Laboratory analysis of a grab sample is performed periodically to confirm instrument accuracy.

TNC and APPLICABILITY

The hydrogen concentration inside an in service (aligned for fill) WGDT always has the potential to exceed 4% by volume. Therefore, the WGA is required to be FUNCTIONAL whenever a WGDT is in service.

A FUNCTIONAL WGA serves to alert operators of oxygen concentrations that could cause an explosive gas mixture (when oxygen is mixed with hydrogen). To prevent an explosive gas mixture, oxygen concentration inside the in service WGDT is not allowed to exceed 4% by volume. Operator action ensures that the concentration of potentially explosive gas mixtures contained in the waste gas holdup system is maintained below the flammability limits for hydrogen and oxygen. This will minimize the probability of a WGDT rupture, thus, minimizing the probability of an accidental radioactive gas release (Reference 7).

BASES

TNC and APPLICABILITY (continued)

The WGA is FUNCTIONAL when it is operating properly and capable of monitoring oxygen concentration. The WGA shall normally be aligned to the in service WGDT. The WGA can be temporarily aligned to monitor various points in the waste gas holdup system and remain FUNCTIONAL. The duration of any temporary alignment to other points in the waste gas holdup system is limited by the Restoration Time specified for Nonconformance A (which depends on plant operating condition).

CONTINGENCY MEASURES

A.1

If the WGA is NonFUNCTIONAL, manual grab samples must be periodically obtained and analyzed from the in service (aligned for fill) WGDT.

If a FUNCTIONAL WGA is not aligned to the in service WGDT, either a grab sample must be obtained or the WGA realigned to the normal configuration (such that the in service WGDT is monitored at the same periodicity as for a NonFUNCTIONAL WGA).

During normal power operation, manual sampling from the in service WGDT is required at 24 hour intervals (grab sample or realigning the WGA to normal). This sampling interval is sufficient since there should be no significant oxygen content in the tank during normal operation.

During primary system degassing operations, more frequent compensatory sampling is required when the WGA is not FUNCTIONAL (or not aligned to the in service WGDT). This manual sampling is required at 4 hour intervals when degassing of the primary system is in progress. Primary system degassing refers to the intentional removal of hydrogen from the reactor coolant system by either mechanical or chemical means and displacement with an alternate gas (e.g. nitrogen). Degassing does not include normal gas stripping of the letdown flow in the volume control tank (Reference 8).

B.1 and B.2

If oxygen concentration in the in service WGDT > 4% by volume, the potential for an explosive gas mixture exists. This condition requires both immediate action to suspend additions of waste gas to the affected WGDT and immediate initiation of action to reduce the oxygen concentration below 4% by volume. Another tank may be placed in service while the source of oxygen is located and eliminated (Reference 8).

BASES

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.3.7.1

A FUNCTIONAL TEST on the WGA must be performed every 31 days to confirm instrument accuracy. This test consists of an analysis of a known gas standard to perform an accuracy check of the WGA.

TVR 8.3.7.2

A CHANNEL CALIBRATION must be performed every 92 days. The WGA is calibrated using a known oxygen and hydrogen calibration gas standard.

REFERENCES

1. Comtrak Commitment Number 85-052, RETS-Explosive Gas Mixtures (DCR 1638).
2. Letter from Carl W. Giesler (WPSC) to Harold Denton (NRC), "Proposed Amendment No. 66 to the KNPP Technical Specifications," dated March 29, 1985.
3. Comtrak Commitment Number 96-122, Item D, Analyze for Explosive Gas Mixtures with Waste Gas Holdup System.
4. Letter from Morton B. Fairtile (NRC) to D.C. Hintz (WPSC), "Amendment 64," dated July 29, 1985.5. USAR 11.1.2.3, Waste Disposal System, Gas Processing.
6. Technical Specification 5.5.10, Explosive Gas and Storage Tank Radioactivity Monitoring Program.
7. USAR 14.2.3.1, Gas Decay Tank Rupture.
8. USAR 9.2.2, Chemical and Volume Control System (CVCS), System Design and Operation.

8.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

8.5.1 Accumulators

TNC 8.5.1 Accumulator check valves and block valves shall be FUNCTIONAL.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS pressure > 1000 psig.

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. TNC 8.5.1 not met.	A.1 Evaluate OPERABILITY of Accumulators per Technical Specification 3.5.1.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.5.1.1	Verify accumulator check valves are FUNCTIONAL.	18 months
TVR 8.5.1.2	Verify accumulator block valves are checked for "valve open" requirements.	18 months

BASES

BACKGROUND	The requirement for accumulator check valves and block valves was relocated from the previous Custom Technical Specifications (TS) during the conversion to Improved TS in License Amendment 207 (Reference 1), The accumulator discharge check valves (SI-21A(B) and SI-22A(B)) have both an open and closed function. They are considered FUNCTIONAL when they have the ability to pass flow from the accumulator to the RCS. Additionally, the accumulator discharge check valves are considered FUNCTIONAL, during normal plant operation with the safety injection (SI) system in standby, when the check valves are closed and isolating the reactor coolant system from the SI accumulators. The "valve open" requirement for the accumulator block valves (SI-20A(B)) is met when the accumulator block valve open indication in the control room is verified to accurately indicate that the block valve is open by the passing of water from the accumulator to the reactor coolant system (RCS) when the control room indicator indicates the valve is open.
TNC and APPLICABILITY	Accumulator check valves and block valves shall be FUNCTIONAL whenever the SI accumulators are required to be OPERABLE in accordance with TS 3.5.1 (i.e., in MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig) (Reference 2).
CONTINGENCY MEASURES	<u>A.1</u> If any accumulator check valve or block valve is not FUNCTIONAL, OPERABILITY of the associated accumulator(s) must be evaluated per TS 3.5.1.
TECHNICAL VERIFICATION REQUIREMENTS	<u>TVR 8.5.1.1</u> A verification that each accumulator check valve is FUNCTIONAL is required to be performed every 18 months. <u>TVR 8.5.1.2</u> A verification that each accumulator block valve is checked for "valve open" requirements is required to be performed every 18 months.

BASES

REFERENCES

1. License Amendment 207, "Kewaunee Power Station (KPS) – Issuance of Amendment for the Conversion to the Improved Technical Specifications with Beyond Scope Issues (TAC Nos. ME2139, ME2419, ME2420, ME2421, ME3122, ME3460, and ME3544)", dated February 2, 2011.
2. Technical Specification 3.5.1, Accumulators.

8.7 PLANT SYSTEMS

8.7.2 Sealed Source Contamination

TNC 8.7.2 The following requirements for radioactive sources shall be met:

a. Each sealed source containing radioactive material, either In excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material, shall be free of ≥ 0.005 microcuries of removable contamination.

b. A complete inventory of radioactive material sources shall be maintained.

APPLICABILITY: At all times.

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. One or more sealed sources leaking.	A.1 Withdraw the sealed source from use.	Immediately
	<u>AND</u>	
	A.2 Initiate action to repair or dispose of the sealed source in accordance with NRC regulations.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

--NOTE--
The TVRs shall be performed by Licensee personnel or other personnel specifically authorized by the NRC or State.

	VERIFICATION	FREQUENCY
TVR 8.7.2.1	---------------------------NOTE--------------------------- Startup sources inserted in the reactor vessel, fission detectors following exposure to core flux, irradiation sample sources inserted in the reactor vessel, sources enclosed within the Eberline Model 1000 Multi-Source Gamma Calibrator, sources enclosed within the Shepherd Model 89-400 Self–Contained Calibrator, and Hydrogen–3 sources are excluded from this test. -- Perform leakage testing on each sealed source in use containing radioactive materials with a half-life > 30 days and in any form other than gas.	184 days
TVR 8.7.2.2	Perform leakage testing for each sealed source and fission detector not in use.	Prior to placing in use or transferring to another licensee, if not performed within the previous 184 days.
TVR 8.7.2.3	Perform leakage testing for each startup source and fission detector not in use.	Within 31 days prior to being subjected to core flux or installed in the core. <u>AND</u> Following repair or maintenance.

BASES

BACKGROUND

Ingestion or inhalation of source material may give rise to total body or organ irradiation. This specification assures that leakage from radioactive material sources does not exceed allowable limits. In the unlikely event that those quantities of radioactive by-product materials of interest to this specification which are exempt from leakage testing are ingested or inhaled, they represent less than one maximum permissible body burden for total body irradiation. The limits for all other sources (including alpha emitters) are based upon 10 CFR 70.39(c) limits for plutonium (Reference 1).

Leakage is defined as the presence of 0.005 microcuries of the source's radioactive material on the test sample.

The Eberline Model 1000 Multi-Source Calibrator and the J. L. Shepherd Model 89-400 are totally enclosed instrument calibrating assemblies for which leak testing of the enclosed sources is not practical. Leak testing of these sources would require disassembly of the calibration assembly shield, controls, etc., resulting in personnel exposure without corresponding benefits.

The requirements for radioactive sources were relocated from the previous Custom Technical Specification (TS) 4.13, "Radioactive Materials Sources", during the conversion to Improved TS (Reference 2).

TNC and APPLICABILITY

To ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values, each sealed source containing radioactive material, either In excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material, shall be free of ≥ 0.005 microcuries of removable contamination.

Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

A complete inventory of radioactive material sources is also required to be maintained.

These requirements are applicable at all times.

BASES

CONTINGENCY MEASURES

A.1 and A.2

If one or more sealed sources are leaking, actions must immediately be taken to withdraw the sealed source from use.

Additionally, actions must immediately be initiated to repair or dispose of the leaking sealed source in accordance with Nuclear Regulatory Commission (NRC) requirements.

TECHNICAL VERIFICATION REQUIREMENTS

The TVRs specified in this section are modified by a Note, which requires that they shall be performed only by Licensee (Dominion Energy Kewaunee) personnel or by other personnel specifically authorized by the NRC or State of Wisconsin.

TVR 8.7.2.1

Leakage testing is required on each sealed source that is in use, if that source contains any non-gaseous radioactive materials with a half-life > 30 days. This leakage testing must be performed every 184 days.

TVR 8.7.2.1 is modified by a Note, which excludes the following sources from this test: Startup sources inserted in the reactor vessel, fission detectors following exposure to core flux, irradiation sample sources inserted in the reactor vessel, sources enclosed within the Eberline Model 1000 Multi-Source Gamma Calibrator, sources enclosed within the Shepherd Model 89-400 Self–Contained Calibrator, and Hydrogen–3 sources.

TVR 8.7.2.2

Prior to placing any sealed source or fission detector in use, or transferring it to another licensee, leakage testing of the source and fission detector is required, unless it was tested within the previous 184 days.

TVR 8.7.2.3

Leakage testing of each startup source and fission detector that is not in use must be performed within 31 days before it is subjected to core flux or installed for use in the core. Additionally, leakage testing is required after repair or maintenance of the source or fission detector.

BASES

REFERENCES

1. 10 CFR 70.39, "Specific licenses for the manufacture or initial transfer of calibration or reference sources".
2. Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Amendment No. 207 to Facility Operating License No. DPR-43, Dominion Energy Kewaunee, Inc., Kewaunee Power Station, Docket No. 50-305, dated February 2, 2011.

8.8 ELECTRICAL SYSTEMS

8.8.3 Emergency Diesel Generator (EDG) Ventilation Damper Control Air Supply

TNC 8.8.3 EDG ventilation damper control air supply shall be FUNCTIONAL with the following provisions for each EDG:

a. Two compressed air cylinders aligned to the damper controllers;

b. Pressure ≥ 1800 psig in each required air cylinder; and

c. Air leakage downstream of isolation check valve within limits.

APPLICABILITY: Whenever the associated EDG is required to be OPERABLE.

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. Ventilation damper control air supply on one EDG NonFUNCTIONAL for reasons other than Nonconformance B or C.	A.1 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	Immediately
B. Ventilation damper control air supply leakage downstream of isolation check valve on one EDG not within limits.	B.1 Reduce air supply leakage to within limits.	24 hours
	<u>AND</u>	
	B.2 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	Immediately
C. Pressure < 1800 psig in one or more required air cylinders on one EDG.	C.1 Restore air cylinder pressure ≥ 1800 psig.	4 hours
	AND	
	C.2 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	Immediately

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES		RESTORATION TIME
D. Ventilation damper control air supply for both EDGs NonFUNCTIONAL.	D.1	Evaluate OPERABILITY of both EDGs per Technical Specification 3.8.1 and 3.8.2.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

VERIFICATION		FREQUENCY
TVR 8.8.3.1	Verify required air cylinder pressure ≥ 1800 psig.	24 hours
TVR 8.8.3.2	----------------------------NOTE---------------------------- Air supply in excess of a seven-day supply is not required for damper control air supply functionality. --- Verify 30 day supply of compressed air cylinders available on site.	31 days
TVR 8.8.3.3	----------------------------NOTE---------------------------- TNC 8.8.3 remains met if leakage is within limits. --- Verify EDG ventilation system leakage downstream of isolation check valve ≤ 217 SCCM.	92 days
TVR 8.8.3.4	Verify isolation check valve leakage within limits.	In accordance with the Augmented Inservice Testing (IST) Program
TVR 8.8.3.5	Perform calibration of backup air supply regulator.	18 months

BASES

BACKGROUND	Emergency Diesel Generator (EDG) Rooms 1A and 1B are each provided with a ventilation system consisting of a normal-mode supply fan and a vent supply fan with automatic control dampers (reference 1). These dampers are operated by compressed air. Vent supply fans provide both combustion air for the diesel engine and sufficient cooling air to maintain the design basis room temperature (reference 2). Compressed air is normally supplied to EDG ventilation control dampers from the instrument air system. A safety-related backup air supply is provided by two redundant sets of compressed air cylinders (two cylinders per set) for each EDG. One of the two sets of air cylinders is normally aligned to its respective EDG's ventilation damper control air supply. The second set is normally maintained isolated (in reserve). The reserve air cylinder set provides enhanced system reliability as well as flexibility for conduct of maintenance or testing. During normal operation, control air is supplied from the instrument air system at a higher pressure than the backup air supply output. This results in the backup air supply remaining in standby. The aligned (inservice) compressed air cylinders provide backup control air to the damper controllers in the event the normal (instrument) air supply is lost concurrent with a loss of off-site power. Either set of backup air supply cylinders (when placed in service) is capable of supplying compressed air to its respective EDG's damper actuators for seven days. A pressure regulator, at the outlet of each compressed air cylinder set, supplies backup air at reduced pressure of approximately 80 psig. In the event instrument air pressure drops below 80 psig, air to the EDG ventilation damper actuators would continue to be provided from the backup air supply. An isolation check valve in the instrument air supply allows flow of instrument air to the damper controllers, but prevents backflow of backup air (and depletion of the air cylinders) in the event of pressure loss in the instrument air system. Based on a maximum allowed system leakage of 217 SCCM downstream of the isolation check valve, and minimum allowed cylinder air pressure of 1800 psig, the backup air supply can provide control air to the damper actuators on its respective EDG for seven days.
TNC and APPLICABILITY	The EDG ventilation damper control air supply supports EDG OPERABILITY. Therefore, the EDG ventilation damper control air supply must be FUNCTIONAL whenever the associated EDG it supports is required to be OPERABLE.

BASES

TNC and APPLICABILITY (continued)

To be FUNCTIONAL, the EDG ventilation damper control air supply must be capable of supplying air to its associated EDG ventilation damper controllers. The instrument air system provides the normal supply of control air, but is not required for EDG ventilation damper control air supply FUNCTIONALITY. The required control air supply is provided by the compressed air cylinders that comprise the backup air supply. Two compressed air cylinders (one set) are required and must be aligned to provide backup air supply to the damper controllers. The second set of air cylinders enhance system reliability, but are not required for air supply FUNCTIONALITY.

To ensure the required seven day supply of control air from the aligned cylinders, air leakage downstream of the isolation check valves must not be excessive and the minimum pressure in each of the two required backup compressed air cylinders must be at least 1800 psig (pressure in the two inservice cylinders in each set remains equalized via their common air header). Air leakage limits are specified in procedures and vary depending on actual air cylinder pressure. Leakage limits are based on maintaining a seven-day air supply. This correlates to an allowed leak rate of 217 SCCM with air cylinder pressure at the minimum allowed value of 1800 psig, and 323 SCCM with air cylinder pressure at 2000 psig.

Each EDG is supported by its associated ventilation damper control air supply. The ventilation damper control air supply for its associated EDG is required to be FUNCTIONAL whenever that EDG is required to be OPERABLE.

CONTINGENCY MEASURES

A.1

If the ventilation damper control air supply on one EDG is NonFUNCTIONAL for reasons other than excessive system leakage downstream of the isolation check valve or pressure < 1800 psig in one or more required air cylinders, OPERABILITY of the associated EDG may have been adversely affected. Therefore, actions are immediately required to be initiated to evaluate EDG OPERABILITY per Technical Specification 3.8.1 and 3.8.2, depending on the reactor MODE in effect.

Because of the immediate completion time, performance of an evaluation that demonstrates the OPERABILITY of the affected EDG as required by CONTENGENCY MEASURE A.1 would need to be completed in advance of entering Condition A.

BASES

CONTINGENCY MEASURES (continued)

B.1, B.2

If system leakage in the ventilation damper control air supply flow path downstream of the isolation check valve on one EDG exceeds procedurally specified limits, the capability of the system to supply backup control air for the required period of time is degraded. Action is needed within 24 hours to reduce leakage to acceptable values.

Because increases in air system leakage generally develop gradually, discovery of excessive air leakage is likely to occur prior to onset of significant leakage or gross system failure. As such, loss of control air to the dampers is not expected to be imminent under normal operating conditions. Therefore, 24 hours is an acceptable period of time for operators to identify and correct the source of leakage. During this 24 hour period, the system remains capable of supplying air to the ventilation damper controllers considering the heightened operator awareness and availability of the redundant (standby) compressed air cylinders to be placed in service (including availability of additional air cylinders stored onsite).

Additionally, to determine whether OPERABILITY of the associated EDG has been adversely affected by excessive control air leakage, actions are immediately required to be initiated to evaluate EDG OPERABILITY per Technical Specification 3.8.1 and 3.8.2, depending on the reactor MODE in effect. These additional actions address conditions where significant or abnormal types of air leakage (e.g., structural failure of air piping integrity) may have adversely impacted EDG OPERABILITY. Provided that air leakage is not gross (e.g., air supply pressure is reasonably capable of being maintained above 1800 psig and capable of supplying compressed air to its respective EDG's damper actuators for seven days (allowing for replacement of air cylinders to maintain pressure)), then the EDG may be considered OPERABLE with this Nonconformance during the 24 hour restoration time.

C.1, C.2

If pressure is < 1800 psig in one or more required air cylinders on one EDG, the capability of the system to supply backup control air for the required period of time is degraded. Action is needed within four hours to restore air cylinder pressure to acceptable values.

Because pressure in the compressed air cylinders generally decreases gradually and a low pressure alarm is provided to operators, discovery of low pressure is likely to occur prior to significant loss of air from the

BASES

CONTINGENCY MEASURES (continued)

air cylinders. As such, loss of control air to the dampers is not expected to be imminent under normal operating conditions. Therefore, four hours is an acceptable period of time for operators to identify and correct the cause of the low air pressure. During this four hour period, the system remains capable of supplying air to the ventilation damper controllers considering the heightened operator awareness and availability of the redundant (standby) compressed air cylinders to be placed in service (including availability of additional air cylinders stored onsite).

Additionally, to determine whether OPERABILITY of the associated EDG has been adversely affected by significantly low air pressure, actions are immediately required to be initiated to evaluate EDG OPERABILITY per Technical Specification 3.8.1 and 3.8.2, depending on the reactor MODE in effect. These additional actions address conditions where significant or abnormal types of pressure loss (e.g., structural failure of air piping integrity) may have adversely impacted EDG OPERABILITY.

D.1

If the ventilation damper control air supply for both EDGs is NonFUNCTIONAL, OPERABILITY of both EDGs may have been adversely affected. Therefore, actions are immediately required to be initiated to evaluate EDG OPERABILITY per Technical Specification 3.8.1 and 3.8.2, depending on the reactor MODE in effect.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.8.3.1

Verification that pressure ≥ 1800 psig in the required (aligned) air cylinders must be performed every 24 hours. Although only the aligned (inservice) air cylinders are required to be verified, pressure in the isolated (standby) compressed air cylinders is also typically monitored to maintain their availability for use.

TVR 8.8.3.2

Verification must be performed every 31 days that a 30-day supply of EDG ventilation control air, contained in appropriate compressed air cylinders, is available on site. This verification is modified by a Note that an air supply beyond a seven-day supply is not required for damper control air supply FUNCTIONALITY. This is an allowed exception to TVR 7.6.1. A 30-day supply is provided as defense in

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

depth. Deficiency in the 30-day air supply would be addressed via the corrective action process.

TVR 8.8.3.3

Verification that EDG ventilation system leakage, downstream of the isolation check valve, ≤ 217 SCCM must be performed every 92 days.

This verification is modified by a Note, which states that TNC 8.8.3 remains met if leakage is within limits. This is an allowed exception to TVR 7.6.1. Since leakage limits are based on actual air cylinder pressure, leakage is permitted to exceed 217 SCCM if air pressure is sufficiently high. However, TNC 8.8.3 allows a minimum cylinder air pressure of 1800 psig. Therefore, leakage should not normally exceed 217 SCCM. Excessive leakage would be addressed via the corrective action process.

TVR 8.8.3.4

Verification that isolation check valve leakage is within limits must be performed In accordance with the periodicity specified in the Augmented IST Program.

TVR 8.8.3.5

The air pressure regulator on the outlet of each required set of compressed air cylinders must be calibrated every 18 months.

REFERENCES

1. USAR 9.6.7, Turbine Building and Screenhouse Ventilation System
2. USAR 8.2.3, Emergency Power

8.9 REFUELING OPERATIONS

8.9.4 Radiation Monitoring During REFUELING OPERATIONS

TNC 8.9.4 Monitor radiation levels in the fuel handling areas:

a. Containment

b. Spent Fuel Pool

APPLICABILITY: During REFUELING OPERATIONS.

CONTINGENCY MEASURES

NONCONFORMANCES	CONTINGENCY MEASURES		RESTORATION TIME
A. Radiation levels not continuously monitored.	A.1	If movement of reactor vessel internal components are in progress, place in safe condition.	Immediately
	AND		
	A.2	Cease refueling of the reactor.	Immediately
	AND		
	A.3	Suspend operations which may increase the reactivity of the core.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

VERIFICATION		FREQUENCY
TVR 8.9.4.1	Verify radiation levels are continuously monitored in containment and spent fuel pool areas.	Prior to REFUELING OPERATIONS and every 24 hours thereafter.

BASES

BACKGROUND	Continuous monitoring of radiation levels provides immediate indication of an unsafe condition.

TNC and APPLICABILITY

This TNC requires that radiation levels be monitored both in containment and in the spent fuel pool area during REFUELING OPERATIONS. A minimum of one radiation monitor capable of detecting releases from a postulated fuel handling accident must be in operation in each of these two areas during REFUELING OPERATIONS.

Radiation monitors that are acceptable for satisfying this TNC are as follows.

<u>Containment</u>

R-2

<u>Spent Fuel Pool</u>

R-5

Source range neutron flux monitoring (for monitoring core reactivity conditions) are addressed by TS 3.9.2 (reference 3).

Other radiation monitors may be used to satisfy this TNC provided that an evaluation determines that the monitor is capable of detecting releases from a postulated fuel handling accident.

CONTINGENCY MEASURES

<u>A.1, A.2, and A.3</u>

If at least one required radiation monitor is not in operation in each of these two areas (containment and spent fuel pool), actions must immediately be initiated to: place any reactor vessel components that are being moved into a safe condition; cease fuel movement; and, suspend operations that may increase the reactivity of the core.

Performance of CONTINGENCY MEASURES A.1, A.2, and A.3 shall not preclude completion of movement of a component to a safe position.

BASES

TECHNICAL VERIFICATION REQUIREMENTS	TVR 8.9.4.1 A verification that radiation levels are continuously monitored in containment and spent fuel pool is required to be performed before REFUELING OPERATIONS begin and every 24 hours thereafter.
REFERENCES	1. Technical Specification 3.3.6, Containment Purge and Vent Isolation Instrumentation 2. Technical Specification 3.3.7, Control Room Post Accident Recirculation (CRPAR) System Actuation Instrumentation 3. Technical Specification 3.9.2, Nuclear Instrumentation 4. Technical Specification 3.9.6, Containment Penetrations 5. Procedure OP-KW-NCL-FH-003, Operations Pre-Refueling Checklist 6. Procedure OP-KW-NCL-FH-004, Operations Refueling Daily Checklist

ATTACHMENT 3

TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

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8.9.1-4	0	February 12, 2011
8.9.2-1	0	February 12, 2011
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8.9.2-4	0	February 12, 2011
8.9.2-5	0	February 12, 2011
8.9.3-1	1	February 21, 2011
8.9.3-2	1	February 21, 2011
8.9.4-1	1	July 21, 2011
8.9.4-2	1	July 21, 2011
8.9.4-3	1	July 21, 2011
8.9.6-1	0	February 12, 2011
8.9.6-2	0	February 12, 2011
8.9.6-3	0	February 12, 2011
8.9.6-4	0	February 12, 2011
8.9.6-5	0	February 12, 2011
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8.9.6-7	0	February 12, 2011
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