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

Serial No. 13-139
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 2012.

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. Richard Repshas at 920-388-8217.

Very truly yours,

Jeffrey T. Stafford

Jeffrey T. Stafford
Director Safety and Licensing
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
2443 Warrenville Road
Suite 210
Lisle, IL 60532-4352

NRC Senior Resident Inspector
Kewaunee Power Station

(Without TS Bases and TRM pages and with 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 3.3.1-33
TS B 3.3.1-52
TS B 3.4.3-3
TS B 3.5.3-1
TS B 3.5.3-2
TS B 3.7.8-5
TS B 3.7.8-6
TS B 3.8.4-1
TS B 3.8.4-2
TS B 3.8.4-3
TS B 3.8.4-4
TS B 3.8.7-3
TS B 3.8.9-3

KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

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.

Although not explicitly stated in Required Action D.1, the requirement to perform SR 3.2.4.2 every 12 hours becomes applicable (per TS 3.2.4) if the Power Range Neutron Flux input to QPTR becomes inoperable with THERMAL POWER >75% RTP. This, in effect, results in Required Action D.2.2 also being required when Required Action D.1.1 is performed with THERMAL POWER >75% RTP (irrespective of the "OR" logical connector between Required Actions D.1 and D.2).

As an alternative to reducing THERMAL POWER per Required Action D.1.2, 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.16

Function 19, Automatic Trip Logic," addresses actuation logic testing of the logic matrices. The Function 19 test is split into three SRs (3.3.1.5, 3.3.1.16, and 3.8.1.16), with different frequencies.

SR 3.3.1.16 is the performance of an ACTUATION LOGIC TEST for the logic matrices associated with Functions 11.a, 11.b, and 13 of TS Table 3.3.1-1. The purpose of this test is to verify performance of those portions of Function 19 that are not tested by SR 3.3.1.5 and SR 3.8.1.16. Note 3 in SR 3.3.1.5 discusses that for Function 19, the logic matrices associated with Functions 11.a, 11.b, and 13 are tested by SR 3.3.1.16 (and not by SR 3.3.1.5).

SR 3.3.1.16 is performed with the plant shutdown, at a refueling (18 months) interval, because if the reactor coolant pump breaker for the reactor protection system logic channel were tested at power, a plant trip would occur.

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety Related Instrumentation."
2. USAR, Chapter 7.
3. USAR, Chapter 6.
4. USAR, Chapter 14.
5. IEEE-279-1968.
6. 10 CFR 50.49.
7. Technical Report EE-0116, Revision 5, "Allowable Values for North Anna Improved Technical Specifications (ITS) Tables 3.3.1-1 and 3.3.2-1, Setting Limits for Surry Custom Technical Specifications (CTS), Sections 2.3 and 3.7, and Allowable Values for Kewaunee Power Station Improved Technical Specifications (ITS) Functions listed in Specification 5.5.16."
8. WCAP-14333-P-A, Rev. 1, "Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times," October 1998.
9. WCAP-10271-P-A, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection System," May 1986.
10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

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).

The minimum temperature for tensioning any reactor vessel head closure bolt, as developed in WCAP-16643 (Reference 1), is the vertical portion of the curve (in Figure 3.4.3-1 and Figure 3.4.3-2) at 73°F (based on 60°F RT_{NDT} plus instrument uncertainty; therefore, use of instruments with lower uncertainty would allow for a correspondingly lower acceptable indicated temperature). With no reactor vessel head closure bolts tensioned and the reactor vessel depressurized (0 psig), the limits specified in Figure 3.4.3-1 and Figure 3.4.3-2 for acceptable operation include temperatures below 73°F (since there is no applied stress in this condition).

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

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

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

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

APPLICABLE SAFETY ANALYSES

The Kewaunee Power Station Licensing Basis does not require performance of an analysis to determine the effects of a Loss of Coolant Accident (LOCA) occurring in MODE 4, nor does it require an analysis to prove ECCS equipment capability to mitigate a MODE 4 LOCA. Massive failure of Class I piping (e.g., RCS) in MODE 4 is not credible. Loss of RCS inventory would be limited to 50 gpm, which is the maximum RCS leakage rate possible (based on RHR pump seal failure). However, Technical Specifications require certain ECCS subsystems to be OPERABLE in MODE 4 to ensure sufficient ECCS flow is available to the core and adequate core cooling is maintained following a loss of RCS inventory in MODE 4.

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

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation.

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

LCO

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

BASES

LCO (continued)

to the core and adequate core cooling is maintained following a loss of RCS inventory.

In MODE 4, an ECCS train consists of a safety injection subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the containment sump. Since automatic SI actuation is not required in MODE 4, subsystems are OPERABLE if they are capable of being manually actuated (e.g., SI pump in pullout, manual valve requiring alignment, etc.).

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the two cold leg injection nozzles (SI pumps) and RCS vessel injection nozzles (RHR pumps). In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS cold legs or vessel.

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

APPLICABILITY

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

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

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS safety injection subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS safety injection subsystem 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.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.3

This SR verifies proper automatic operation of the SW System pumps on an actual or simulated actuation signal. The SW System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. 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. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.4

A CHANNEL CALIBRATION of the fore bay water level instrumentation is performed every 18 months, 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. 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. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR, which is only applicable to fore bay water level instrumentation, is not included in the Standard Improved TS (NUREG-1431). It was added during the conversion to Improved TS in License Amendment 207 (Reference 4) to serve as a means to prove that the fore bay water level instrumentation is OPERABLE, consistent with previous requirements.

SR 3.7.8.5

This SR verifies proper automatic operation of the CW pump breaker trip on an actual or simulated Low-Low Forebay water level trip signal. The CW System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. 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. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

REFERENCES

1. USAR, Section 9.6.2.
2. USAR, Section 6.3.2.
3. USAR, Section 9.3.1.2.
4. 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.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC instrument bus power (via inverters). Consistent with the intent of 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the recommendations of Safety Guide 6 (Ref. 2).

The 125 VDC electrical power system consists of two independent and redundant safety related Class 1E DC electrical power subsystems (Train A and Train B). Each subsystem consists of one 125 VDC battery, the associated battery charger for each battery, and all the associated control equipment and interconnecting cabling. Additionally there is one spare battery charger per subsystem, which provides backup service in the event that the preferred battery charger is out of service. If either spare battery charger is substituted for its associated preferred battery charger, the requirements of independence and redundancy between subsystems continue to be maintained.

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

The Train A and Train B DC electrical power subsystems provide the control power for its associated Class 1E AC power load group, 4.16 kV switchgear, and 480 V load centers. The DC electrical power subsystems also provide DC electrical power to the inverters, which in turn power the AC instrument buses.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each 125 VDC battery is separately housed in a ventilated room. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

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 113.1 V for Battery BRA-101 and 113.6 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 four 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

BACKGROUND (continued)	battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the USAR, Chapter 14 (Ref. 4), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; and b. A worst-case single active failure. The DC Sources - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The DC electrical power subsystems, each subsystem consisting of one battery, either battery charger for each battery and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the subsystem are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). An OPERABLE DC electrical power subsystem requires one battery and respective charger to be operating and connected to the associated DC bus(es).
APPLICABILITY	The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that: a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

BASES

APPLICABILITY (continued)

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

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

The ACTIONS are modified by a Note that allows a 24 hour delay in entering the ACTIONS when a DC electrical power subsystem is inoperable solely due to the room cooler being non-functional, provided the associated room temperature is monitored and maintained within the design environmental requirements and the other DC electrical power subsystem is OPERABLE. The 24 hour allowance is provided in order to perform room cooler maintenance. If during the 24 hour period the other DC electrical power subsystem becomes inoperable, the associated ACTIONS for an inoperable DC electrical power subsystem must immediately be entered. This 24 hour time period is acceptable because the room containing the DC electrical power subsystems is procedurally monitored on a regular basis to ensure conditions are within design environmental requirements of 120°F during this time .

A.1, A.2, and A.3

Condition A represents one required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

BASES

ACTIONS

The ACTIONS are modified by a Note that allows a 24 hour delay in entering the ACTIONS when one or both inverters in one train are inoperable solely due to the room cooler being non-functional, provided the associated room temperature is monitored and maintained within the design environmental requirements and both inverters in the other train are OPERABLE. The 24 hour allowance is provided in order to perform room cooler maintenance. If during the 24 hour period one or both of the inverters in the other train become inoperable, the associated ACTIONS for the inoperable inverter(s) must immediately be entered. This 24 hour time period is acceptable because the room containing the inverters is procedurally monitored on a regular basis to ensure conditions are within design environmental requirements of 120° F during this time.

A.1

With a Train A or Train B inverter inoperable, its associated AC instrument bus becomes inoperable until it is re-energized from its inverter using internal AC source/rectifier. For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the instrument bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument bus is powered from its constant voltage source, it is relying upon interruptible AC electrical power sources (offsite and onsite). Power to an instrument bus is provided in the following order: 1) filtered AC through the inverter (referred to as "normal"); 2) DC changed to AC via the inverter (referred to as "standby"); and 3) non-filtered AC through the inverter via a static switch (referred to as "alternate").

B.1

With two inverters in the same train inoperable, the remaining inverters are capable of supporting the minimum safety function necessary to shutdown the reactor and maintain it in a safe condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in one of the two remaining inverters could result in the minimum ESF functions not being supported. Therefore, one of the inverters must be restored to OPERABLE status within 2 hours.

BASES

LCO (continued)	related redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV buses from being powered from the same offsite circuit.
APPLICABILITY	The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that: a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA. Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."
ACTIONS	The ACTIONS are modified by a Note that allows a 24 hour delay in entering the ACTIONS when one or more electrical power distribution subsystems are inoperable solely due to the room cooler being non-functional, provided the associated room temperature is monitored and maintained within the design environmental requirements and the electrical power distribution subsystems in the other train are OPERABLE. The 24 hour allowance is provided in order to perform room cooler maintenance. If during the 24 hour period the buses subsequently become inoperable such that a loss of function occurs, the associated ACTIONS for the inoperable DC electrical power subsystem(s) must immediately be entered. This 24 hour time period is acceptable because the room containing the AC, DC, and AC instrument bus electrical power distribution subsystems is procedurally monitored on a regular basis to ensure conditions are within design environmental requirements of 120°F during this time. <u>A.1</u> With one or more Train A and B required AC electrical power distribution subsystem (except AC instrument buses), inoperable and a loss of function has not occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown

ATTACHMENT 2

TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

KEWAUNEE POWER STATION TECHNICAL REQUIREMENTS MANUAL CHANGES

TRM PAGES:
TRM 8.3.9 Rev. 1, pages 8.3.9-1 through 8.3.9-8
TRM 8.5.2 Rev. 1, pages 8.5.2-1 through 8.5.2-6
TRM 8.7.5 Rev. 1, pages 8.7.5-1 through 8.7.5-29
TRM 8.8.1 Rev. 1, pages 8.8.1-1 through 8.8.1-10
TRM 8.8.2 Rev. 1, pages 8.8.2-1 through 8.8.2-8
TRM 8.8.2 Rev. 2, pages 8.8.2-1 through 8.8.2-8
TRM 8.8.3 Rev. 1, pages 8.8.3-1 through 8.8.3-10
TRM 8.8.4 Rev. 0, pages 8.8.4-1 through 8.8.4-11

KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

8.3 INSTRUMENTATION

8.3.9 Reactor Thermal Output Monitoring

TNC 8.3.9 The Plant Process Computer System (PPCS) Reactor Thermal Output (RTO) monitoring program shall be FUNCTIONAL with the following provisions:

a. Steam generator conductivity shall be ≤ 20 μmhos;

b. Ultrasonic Flow Measurement Device (UFMD) feedwater flow correction factors shall be in service;

c. UFMD feedwater temperature correction factors shall be in service.

APPLICABILITY: THERMAL POWER > 1749 MWth.

CONTINGENCY MEASURES

--NOTE--
Multiple Nonconformance entries are allowed.

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. Steam generator conductivity > 20 μmhos.	A.1 Initiate action to insert temperature correction factors.	Immediately
	<u>AND</u>	
	A.2 Initiate action to reduce UFMD Operating Limit to ≤ 1769 MWth.	Immediately
	<u>AND</u>	
	A.3 Reduce THERMAL POWER to ≤ 1769 MWth (15 minute average) and to ≤ 1768.7 MWth (8 hour average).	24 hours after the last performance of a secondary calorimetric calculation

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
B. Feedwater flow correction factor not in service. OR Feedwater flow correction factor has inserted value. OR Feedwater flow correction factor questionable.	B.1 Initiate action to reduce UFMD Operating Limit to ≤ 1749 MWth. AND B.2 Reduce THERMAL POWER to ≤ 1749 MWth (15 minute average) and to ≤ 1748.7 MWth (8 hour average).	Immediately 24 hours after the last performance of a secondary calorimetric calculation
C. Feedwater temperature correction factor not in service. OR Feedwater temperature correction factor has inserted value. OR Feedwater temperature correction factor questionable.	C.1 Initiate action to reduce UFMD Operating Limit to ≤ 1769 MWth. AND C.2 Reduce THERMAL POWER to ≤ 1769 MWth (15 minute average) and to ≤ 1768.7 MWth (8 hour average).	Immediately 24 hours after the last performance of a secondary calorimetric calculation

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
D. RTO monitoring program NonFUNCTIONAL.	D.1 Reduce THERMAL POWER to ≤ 1749 MWth.	24 hours after the last performance of a secondary calorimetric calculation

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.3.9.1	Perform signal conditioning/processing unit self test.	6 months <u>AND</u> After calibration
TVR 8.3.9.2	Reboot the UFM and UTM.	6 months
TVR 8.3.9.3	Perform reflected signal strength indication scan.	12 months
TVR 8.3.9.4	Recalibrate the signal conditioning/processing unit.	18 months

BASES

BACKGROUND

Feedwater flow is measured using the venturi flow meters on each of the feedwater line headers. The venturi feedwater flow is corrected using the Crossflow ultrasonic flow measurement devices (UFMDs) that are located on the A and B feedwater lines. Feedwater flow provides input into the secondary calorimetric calculation. In the event that the feedwater flow correction factors from the UFMD system become questionable, reactor thermal power output must be reduced in a specified time period to a power output consistent with secondary calorimetric power measurement uncertainty of 2.0 percent. If power level has been reduced due to questionable feedwater flow correction factors from the UFMD system, the feedwater flow venturis may be corrected for fouling using the full flow feedwater bypass line (FBL). The total FBL flow section feedwater flow measurement uncertainty is 0.45 percent; however, reactor thermal power output is limited to a power output consistent with a 2.0 percent secondary calorimetric power measurement uncertainty (reference 1).

Correcting venturi feedwater flow with the Crossflow System is the basis for the measurement uncertainty recapture (MUR) power uprate, which increased licensed rated reactor thermal power output.

Calorimetric power measurement uncertainty is used in the determination of reactor thermal power output. Secondary calorimetric power measurement is obtained from measurement of feedwater flow, feedwater inlet temperature to the steam generator and steam pressure. This power measurement is performed periodically to ensure that reactor thermal power output does not exceed licensed limits. It is also used to calibrate/adjust the nuclear instrumentation on a periodic basis to ensure that the nuclear instrumentation is indicating reactor power consistent with the secondary calorimetric power measurement.

The MUR power uprate was achieved by installation of AMAG Crossflow Ultrasonic Flow Measurement Devices (UFMDs) on the A and B Feedwater Loops, which allow reactor thermal power output to be measured more accurately. Each UFMD consists of an ultrasonic flow meter (UFM) and ultrasonic temperature monitor (UTM). The Crossflow UFMDs derive feedwater flow and feedwater temperature correction factors that are input into the Plant Process Computer System (PPCS). Use of the UFMD correction factors along with the relaxation of the 10 CFR 50, Appendix K rule regarding power measurement uncertainty, allows for operation at a power level consistent with the actual power measurement uncertainty (reference 2).

BASES

BACKGROUND (continued)	When the UFM and UTM are providing reliable correction factors, total secondary calorimetric power measurement uncertainty is 0.6%. If a UTM correction factor becomes questionable, the total secondary calorimetric power measurement uncertainty is 0.8%. If a UFM correction factor becomes questionable, the total secondary calorimetric power measurement uncertainty is 2.0% (reference 2). Reactor thermal power output must be reduced in a specified time period to a power output consistent with the appropriate secondary calorimetric power measurement uncertainty if the correction factors from the UFMD system specified above become questionable. Additional information on ensuring adherence to the maximum THERMAL POWER limit is provided via a safety evaluation discussed in NRC Regulatory Issue Summary (RIS) 2007-21, Revision 1 (reference 3).
TNC and APPLICABILITY	The Plant Process Computer System (PPCS) Reactor Thermal Output (RTO) monitoring program is required to be FUNCTIONAL whenever reactor thermal power is > 1749 MWth (98.7%; as indicated by the 15 minute average). Operation up to the maximum licensed reactor power level (1772 MWth) requires the UFMD feedwater flow and temperature correction factors to be in service. Therefore, the following provisions must be met whenever the PPCS RTO monitoring program is required to be FUNCTIONAL: a) Steam generator conductivity shall be ≤ 20 μmhos; b) the UFMD feedwater flow correction factors shall be in service; and, c) the UFMD feedwater temperature correction factors shall be in service. A questionable feedwater flow or temperature correction factor is the last good correction factor received from the UFMD system prior to a condition that causes the system to stop providing automatic updates. Since the questionable correction factor is good, the PPCS RTO monitoring program remains FUNCTIONAL when using a questionable correction factor. However, since questionable correction factors are not updated, operation with their use is limited to the time stated in the ACTIONS section for the respective questionable correction factor.

BASES

CONTINGENCY MEASURES

The CONTINGENCY MEASURES are modified by a Note allowing for multiple Condition entries to be entered concurrently.

The various CONTINGENCY MEASURES direct reducing reactor power and the Ultrasonic Flow Measurement Device (UFMD) Operating Limit to specified values within 24 hours of the last performance of a secondary calorimetric calculation (i.e., the last calorimetric using a valid UFMD correction factor that was performed before the associated Nonconformance occurred) (reference 4). Secondary calorimetric calculations are performed in accordance with plant procedures (reference 5).

The 24 hour allowance is based on the daily nuclear power range surveillance (SR 3.3.1.2) (reference 4). It is also based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together, these factors demonstrate that a difference between the calorimetric heat balance calculation and the power range channel output of more than + 2% reactor thermal power is not expected in any 24 hour period.

<u>A.1</u>

Uncertainty of the ultrasonic temperature monitors (UTM) is impacted if feedwater total dissolved solids (TDS) are greater than 20 ppm (steam generator conductivity > 20 µmhos). The UTMs are NonFUNCTIONAL when TDS is greater than 20 ppm. In this condition, the associated Actions require immediate initiation of action to insert current temperature correction factors and to reduce the UFMD Operating Limit to ≤ 1769 MWth. Although the UFMD Operating Limit is automatically set to 1769 MWth if any temperature correction factor is questionable, the system does not automatically detect high steam generator conductivity; therefore, the last good correction factors must be inserted manually.

Additionally, the associated CONTINGENCY MEASURES require reducing reactor power to ≤ 1769 MWth (as indicated by the 15 minute average) and to ≤ 1768.7 MWth (as indicated by the 8 hour average) within 24 hours of the last performance of a secondary calorimetric calculation (that was performed before this Nonconformance was entered).

Since the UTMs are rendered NonFUNCTIONAL when feedwater TDS > 20 ppm, this condition needs to be evaluated for simultaneous entry into Nonconformance C.

BASES

CONTINGENCY MEASURES (continued)

B.1

If any feedwater flow correction factor is either not in service, has an inserted value, or is questionable, the power measurement uncertainty may be higher than the ideal value. In this condition, the associated Actions require immediate initiation of action to reduce the UFMD Operating Limit to ≤ 1749 MWth. This action is performed on the plant process computer system (PPCS). Note that the UFMD Operating Limit is automatically set to 1749 MWth if any flow correction factor is questionable.

Additionally, the associated CONTINGENCY MEASURES require reducing reactor power to ≤ 1749 MWth (as indicated by the 15 minute average) and to ≤ 1748.7 MWth (as indicated by the 8 hour average) within 24 hours of the last performance of a secondary calorimetric calculation (that was performed before this Nonconformance was entered).

C.1

If any feedwater temperature correction factor is either not in service, has an inserted value, or is questionable, the power measurement uncertainty may be higher than the ideal value. In this condition, the associated Actions require immediate initiation of action to reduce the UFMD Operating Limit to ≤ 1769 MWth. This action is performed on the PPCS. Note that the UFMD Operating Limit is automatically set to 1769 MWth if any temperature correction factor is questionable.

Additionally, the associated CONTINGENCY MEASURES require reducing reactor power to ≤ 1769 MWth (as indicated by the 15 minute average) and to ≤ 1768.7 MWth (as indicated by the 8 hour average) within 24 hours of the last performance of a secondary calorimetric calculation (that was performed before this Nonconformance was entered).

D.1

If the RTO monitoring program is NonFUNCTIONAL, the primary method for accurately monitoring RTO is unavailable. In this condition, the associated CONTINGENCY MEASURES require reducing reactor power to ≤ 1749 MWth (as indicated by calorimetric (reference 4)) within 24 hours of the last performance of a secondary calorimetric calculation (that was performed before this Nonconformance was entered).

BASES

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.3.9.1

A self test of the signal conditioning/processing unit is required to be performed every 6 months. This test is performed automatically by installed software (reference 4). A self test must also be performed following calibration of the unit prior to returning it to service.

TVR 8.3.9.2

The UFM and UTM signal conditioning/processing unit is required to be rebooted every 6 months (reference 4).

TVR 8.3.9.3

A reflected signal strength indication scan is required to be performed annually (reference 4).

TVR 8.3.9.4

The signal conditioning/processing unit is required to be recalibrated every 18 months. This recalibration is typically performed every refueling outage by returning the unit to the vendor (reference 4).

REFERENCES

1. USAR Section 10.2.2.7, Main Feedwater System.
2. USAR Section 14.0.4.1, Calorimetric Error Instrumentation Accuracy.
3. NRC Regulatory Issue Summary (RIS) 2007-21, Rev. 1, “Adherence to Licensed Power Limits,” February 9, 2009.
4. KPS License Amendment 168 and associated NRC safety evaluation, dated July 8, 2003.
5. Procedure SP-87-125, “Shift Instrument Channel Checks – Operating.”

8.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

8.5.2 Emergency Core Cooling System (ECCS), Residual Heat Removal System, and Internal Containment Spray System Gas Accumulation

TNC 8.5.2 All required Safety Injection (SI), Residual Heat Removal (RHR) and Internal Containment Spray (ICS) trains shall be sufficiently full of water.

APPLICABILITY: Whenever the associated SI, RHR and ICS trains are required to be OPERABLE by Technical Specifications (TS).

CONTINGENCY MEASURES

---NOTE---

Separate Nonconformance entry is allowed for each ECCS train, RHR train, and ICS train.

NONCONFORMANCE	CONTINGENCY MEASURE		RESTORATION TIME
A. One or more required ECCS trains not sufficiently full of water.	A.1	Evaluate OPERABILITY of ECCS train(s) per Technical Specification 3.5.2.	Immediately
	<u>AND</u>		
	A.2	Evaluate OPERABILITY of ECCS train(s) per Technical Specification 3.5.3.	Immediately
B. One or more required RHR trains not sufficiently full of water.	B.1	Evaluate OPERABILITY of RHR train(s) per Technical Specification 3.4.6.	Immediately
	<u>AND</u>		
	B.2	Evaluate OPERABILITY of RHR train(s) per Technical Specification 3.4.7.	Immediately
	<u>AND</u>		
	B.3	Evaluate OPERABILITY of RHR train(s) per Technical Specification 3.4.8.	Immediately

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURE		RESTORATION TIME
C. One or more ICS train(s) not sufficiently full of water.	C.1	Evaluate OPERABILITY of ICS train(s) per Technical Specification 3.6.6.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

VERIFICATION		FREQUENCY
TVR 8.5.2.1	Verify SI, RHR and ICS piping is sufficiently full of water.	92 days

BASES

BACKGROUND

The U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 2008-01 (reference 3) to address the issue of gas accumulation in the emergency core cooling, decay heat removal (DHR), and containment spray systems. At Kewaunee the DHR function is performed by the RHR system. Because the RHR system serves two functions, ECCS and DHR, it is listed separately, covering each function, as appropriate.

The ECCS and ICS System pumps are normally in a standby non-operating mode. As such, some flow path piping has the potential to develop pockets of entrained gases. Plant operating experience and analysis has shown that after proper system filling (following maintenance or refueling outages), some entrained non-condensable gases remain. These gases will form small voids, which remain stable in the system in both normal and transient operation. Mechanisms postulated to increase the void size are gradual in nature, and the system is operated in accordance with procedures to preclude growth in these voids. In addition, other mechanisms, such as valve seat leakage into the stagnant systems from other gas-laden sources, system fluid velocities and physical geometries can cause a gradual increase in the size of gas voids.

The system is sufficiently full of water when the voids and pockets of entrained gases in the ECCS, RHR, and ICS piping are small enough in size and number to not interfere with the proper operation of the ECCS, RHR, or ICS systems. Verification that the ECCS, RHR, and ICS piping is sufficiently full of water can be performed by venting the necessary accessible high point ECCS, RHR, and ICS vents, using NDE, or using other engineering-justified means.

Maintaining the piping and components from the ECCS pump suction sources to the final isolation valve before connection to the RCS sufficiently full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent pump cavitation and air binding, water hammer, and pumping of excess non-condensable gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling.

Exceptions to the ECCS system being sufficiently full of water are discussed in USAR Section 6.2.2.3 (Reference 1). These exceptions are designed such that they can accommodate a void without affecting the operability of the associated systems.

BASES

BACKGROUND (continued)	Maintaining the piping and components from the ICS pump suction sources to the discharge to containment sufficiently full of water ensures that the system will perform properly, injecting its full capacity into containment upon demand.
TNC and APPLICABILITY	All required SI, RHR and ICS trains shall be sufficiently full of water to be FUNCTIONAL whenever the associated SI, RHR and ICS trains are required to be OPERABLE by Technical Specifications (TS).
CONTINGENCY MEASURES	The Actions are modified by a Note. The Note provides clarification that each train allows separate entry into a Condition. This is allowed based upon the FUNCTIONAL independence of each train. The SI and RHR systems together comprise the ECCS system. These systems work in tandem to provide core cooling and negative reactivity to ensure that the reactor core is protected. Thus, the SI/RHR system consists of two trains and the ICS system consists of two trains. <u>A.1 and A.2</u> With one or more ECCS train not sufficiently full of water, it is not capable of delivering design flow to the RCS. When a train is not sufficiently full of water, the appropriate TS ACTION(S) must be entered immediately. Individual components are NonFUNCTIONAL if they are not capable of performing their design function or supporting systems are not available. <u>B.1, B.2, and B.3</u> Condition B is applicable when one or more trains of RHR are not sufficiently full of water. In this condition, the RHR system needs to be considered for decay heat removal requirements. When a train is not sufficiently full of water, the appropriate TS ACTION(S) must be entered immediately.

BASES

CONTINGENCY MEASURES (continued)

C.1

Condition C is applicable when one or more trains of ICS are not sufficiently full of water and not capable of delivering design flow to containment. When a train is not sufficiently full of water, it is considered NonFUNCTIONAL and the appropriate TS ACTION must be entered immediately.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.5.2.1

The ECCS and ICS System pumps are normally in a standby non-operating mode. As such, some flow path piping has the potential to develop pockets of entrained gases. Plant operating experience and analysis has shown that after proper system filling (following maintenance or refueling outages), some entrained non-condensable gases remain. These gases will form small voids, which remain stable in the system in both normal and transient operation. Mechanisms postulated to increase the void size are gradual in nature, and the system is operated in accordance with procedures to preclude growth in these voids. In addition, other mechanisms, such as valve seat leakage into the stagnant systems from other gas-laden sources, system fluid velocities and physical geometries can cause a gradual increase in the size of gas voids.

To provide additional assurances that the system will function, verification is performed every 92 days that the system is sufficiently full of water. The system is sufficiently full of water when the voids and pockets of entrained gases in the ECCS, RHR, and ICS piping are small enough in size and number to not interfere with the proper operation of the ECCS, RHR, or ICS systems. Verification that the ECCS, RHR, and ICS piping is sufficiently full of water can be performed by venting the necessary accessible high point ECCS, RHR, and ICS vents, using NDE, or using other Engineering-justified means.

Maintaining the piping and components from the ECCS pump suction sources to the final isolation valve before connection to the RCS sufficiently full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent pump cavitation and air binding, water hammer, and pumping of excess non-condensable gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 92-day frequency takes into consideration the gradual nature of the postulated gas accumulation mechanisms.

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

Maintaining the piping and components from the ECCS pump suction sources to the final isolation valve before connection to the RCS sufficiently full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent pump cavitation and air binding, water hammer, and pumping of excess non-condensable gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 92-day frequency takes into consideration the gradual nature of the postulated gas accumulation mechanisms.

Exceptions to the ECCS system being sufficiently full of water are discussed in USAR Section 6.2.2.3 (Reference 1). These exceptions are designed such that they can accommodate a void without affecting the operability of the associated systems.

Maintaining the piping and components from the ICS pump suction sources to the discharge to containment sufficiently full of water ensures that the system will perform properly, injecting its full capacity into containment upon demand. The 92-day frequency takes into consideration the gradual nature of the postulated gas accumulation mechanisms.

REFERENCES

1. USAR 6.2, "Safety Injection System."
2. USAR 6.4, "Internal Containment Spray System."
3. NRC Generic Letter 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems.

8.7 PLANT SYSTEMS

8.7.5 Snubbers

TNC 8.7.5 Each snubber listed in Table 8.7.5-1 shall be FUNCTIONAL.

APPLICABILITY: When the associated supported system is required to be OPERABLE.

CONTINGENCY MEASURES

-----NOTE-----
Separate entry is allowed for each snubber.

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. One or more required snubbers NonFUNCTIONAL.	A.1 Evaluate Technical Specification LCO 3.0.8 compliance.	Immediately
	AND	
	A.2 Verify at least one train (or subsystem) of systems supported by the NonFUNCTIONAL snubber(s) would remain capable of performing its required safety or support function for postulated design loads other than seismic loads.	Immediately
	AND	

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. (continued)	A.3.1 -------------NOTE------------------ Only applicable if LCO 3.0.8.a is used. -------------------------------------- Verify at least one AFW train not associated with the NonFUNCTIONAL snubber is available. <u>OR</u> A.3.2 -------------NOTE------------------ Only applicable if LCO 3.0.8.b is used. -------------------------------------- Verify at least one AFW train not associated with the NonFUNCTIONAL snubber or alternative means of core cooling is available.	 Immediately Immediately
B. CONTINGENCY MEASURE A.2 and associated Restoration Time not met.	B.1 Declare supported system LCO not met and enter applicable Required Action.	Immediately
C. CONTINGENCY MEASURE A.3 and associated Restoration Time not met.	C.1 Initiate action to restore associated snubber to a FUNCTIONAL status. <u>AND</u> C.2 Initiate action to manage risk.	Immediately Immediately

TECHNICAL VERIFICATION REQUIREMENTS

VERIFICATION		FREQUENCY
TVR 8.7.5.1	Perform snubber examination and testing in accordance with the Snubber Test Program.	In accordance with the Snubber Test Program

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
AC-H68	Seismic	Component Cooling	TS 3.7.7	1, 2, 3, 4	Dual
AC-H78	Seismic	Reactor Coolant System Containment	TS 3.4.8 TS 3.6.1	5 1, 2, 3, 4	Dual
CS-H33A	Seismic	ECCS ECCS Internal Containment Spray Containment	TS 3.5.2 TS 3.5.3 TS 3.6.6 TS 3.6.1	1, 2, 3 4 1, 2, 3, 4 1, 2, 3, 4	Dual
CS-H39	Seismic	ECCS ECCS Internal Containment Spray Containment	TS 3.5.2 TS 3.5.3 TS 3.6.6 TS 3.6.1	1, 2, 3 4 1, 2, 3, 4 1, 2, 3, 4	Dual
CVC-H84	Seismic	ECCS ECCS Internal Containment Spray	TS 3.5.2 TS 3.5.3 TS 3.6.6	1, 2, 3 4 1, 2, 3, 4	Dual
CVC-H96	Seismic	ECCS ECCS Internal Containment Spray	TS 3.5.2 TS 3.5.3 TS 3.6.6	1, 2, 3 4 1, 2, 3, 4	Dual
CVC-H143	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
CVC-H161	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
CVC-H162	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
CVC-H173	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
CVC-H355	Seismic	CVCS	TRM 8.1.1	1, 2, 3, 4, 5, 6	Dual
CVC-H356	Seismic	CVCS	TRM 8.1.1	1, 2, 3, 4, 5, 6	Dual
CVC-H357	Seismic	CVCS	TRM 8.1.1	1, 2, 3, 4, 5, 6	Dual
CVC-H449	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
CVC-H450	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
ICS-H7	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
ICS-H8	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
ICS-H9	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
ICS-H10	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
ICS-H11	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
ICS-H12	Seismic Dynamic	Internal Containment Spray Containment	TS 3.6.6 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Single
MS-H121	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3, 4	Dual
MS-H129	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3, 4	Dual
RAC-H21	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RAC-H37	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RAC-H38	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RAC-H39	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RAC-H75	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RAC-H76NE	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RAC-H76SE	Seismic	Component Cooling Containment	TS 3.7.7 TS 3.6.1	1, 2, 3, 4 1, 2, 3, 4	Dual
RC-H29A	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RC-H72	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RC-H86	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Containment	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.6.1	1, 2 3 4 5 5 1, 2, 3, 4	Dual
RC-H87	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Containment	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.6.1	1, 2 3 4 5 5 1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RCVC-H31A	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H31B	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H32	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H33A	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H33B	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H34	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RCVC-H35	Seismic	Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System	TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8	1, 2 3 4 5 5	Dual
RCVC-H36	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
RCVC-H186	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
RCVC-H191	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
RCVC-H245	Seismic	Containment	TS 3.6.1	1, 2, 3, 4	Dual
RHR-H10H	Seismic	Residual Heat Removal Residual Heat Removal Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment Internal Containment Spray	TS 3.5.3 TS 3.5.4 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1 TS 3.6.6	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4 1, 2, 3, 4	Dual
RHR-H12A	Seismic	Residual Heat Removal Residual Heat Removal Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment Internal Containment Spray	TS 3.5.3 TS 3.5.4 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1 TS 3.6.6	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4 1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RHR-H12B	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H16A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H21A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H35A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RHR-H36A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H38A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H41A	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RHR-H49	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RRHR-H14	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RRHR-H15	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
RRHR-H18	Seismic	Residual Heat Removal	TS 3.5.3	1, 2, 3	Dual
		Residual Heat Removal	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RRHR-H55	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RRHR-H57	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H15A	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H2	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H2A	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H38	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H59	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H61	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.2 TS 3.5.3 TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 1, 2 3 4 5 5 6 6 1, 2, 3, 4	Dual
RSI-H63	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.2 TS 3.5.3 TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 1, 2 3 4 5 5 6 6 1, 2, 3, 4	Dual
RSI-H67	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.2 TS 3.5.3 TS 3.4.4 TS 3.4.5 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 1, 2 3 4 5 5 6 6 1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H78	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H83	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H94	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H95	Seismic	Safety Injection	TS 3.5.2	1, 2, 3	Dual
		Safety Injection	TS 3.5.3	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H96	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.2 TS 3.5.3 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4	Dual
RSI-H97W	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.2 TS 3.5.3 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4	Dual
RSI-H97S	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.3 TS 3.5.4 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4	Dual
RSI-H98	Seismic	Safety Injection Safety Injection Reactor Coolant System Reactor Coolant System Reactor Coolant System Refueling Refueling Containment	TS 3.5.3 TS 3.5.4 TS 3.4.6 TS 3.4.7 TS 3.4.8 TS 3.9.3 TS 3.9.4 TS 3.6.1	1, 2, 3 4 4 5 5 6 6 1, 2, 3, 4	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H99	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H100	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RSI-H101	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
RSI-H102	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Containment	TS 3.6.1	1, 2, 3, 4	
RTD-H2	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
RTD-H6	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
RTD-H8	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
RTD-H11	Seismic	Reactor Coolant System	TS 3.4.4	1, 2	Dual
		Reactor Coolant System	TS 3.4.5	3	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
SGB-H189	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
SI-H6D	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Reactor Coolant System	TS 3.4.6	4	
		Reactor Coolant System	TS 3.4.7	5	
		Reactor Coolant System	TS 3.4.8	5	
		Refueling	TS 3.9.3	6	
		Refueling	TS 3.9.4	6	
		Internal Containment Spray	TS 3.6.6	1, 2, 3, 4	
SI-H35	Seismic	Safety Injection	TS 3.5.3	1, 2, 3	Dual
		Safety Injection	TS 3.5.4	4	
		Containment	TS 3.6.1	1, 2, 3, 4	
SS-H67	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
SS-H73	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
SS-H76	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
SS-H86	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
SS-H87	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	
SS-H88	Seismic	Auxiliary Feedwater	TS 3.7.5	1, 2, 3	Dual
		Reactor Coolant System	TS 3.4.4	1, 2	
		Reactor Coolant System	TS 3.4.5	3	

Table 8.7.5-1
Snubbers

Snubber	Support Loads	Associated System(s)	Associated TS/TRM	Applicable MODES	Trains Affected
SS-H103	Seismic	Auxiliary Feedwater Reactor Coolant System Reactor Coolant System	TS 3.7.5 TS 3.4.4 TS 3.4.5	1, 2, 3 1, 2 3	Dual
SS-H129	Seismic	Auxiliary Feedwater Reactor Coolant System Reactor Coolant System	TS 3.7.5 TS 3.4.4 TS 3.4.5	1, 2, 3 1, 2 3	Dual
SS-H146	Seismic	Auxiliary Feedwater Reactor Coolant System Reactor Coolant System	TS 3.7.5 TS 3.4.4 TS 3.4.5	1, 2, 3 1, 2 3	Dual
SS-H150	Seismic	Auxiliary Feedwater Reactor Coolant System Reactor Coolant System	TS 3.7.5 TS 3.4.4 TS 3.4.5	1, 2, 3 1, 2 3	Dual
SS-H156	Seismic	Auxiliary Feedwater Reactor Coolant System Reactor Coolant System	TS 3.7.5 TS 3.4.4 TS 3.4.5	1, 2, 3 1, 2 3	Dual
SW-H401	Seismic	Service Water	TS 3.7.8	1, 2, 3, 4	Dual

BASES

BACKGROUND

Shock suppressors (snubbers) are designed to prevent unrestrained pipe motion under dynamic loads, as might occur during seismic activity or severe plant transients, while allowing normal thermal motion during startup or shutdown. The consequence of a NonFUNCTIONAL snubber is an increase in the probability of structural damage to piping as a result of a seismic event or other events initiating dynamic loads. It is therefore required that all snubbers designed to protect the reactor coolant and other safety-related systems or components be FUNCTIONAL during reactor operation. The intent of TRM 8.7.5 is to restrict reactor operation with defective safety-related shock suppressors.

The requirements for snubbers were relocated from the previous Custom Technical Specification (TS) 3.14, "Shock Suppressors (Snubbers)", during the conversion to Improved TS (Reference 1).

TRM 8.7.5 also specifies the snubbers applicable to TS LCO 3.0.8, which establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s).

LCO 3.0.8 was developed in TSTF-372, Revision 4, "Addition of LCO 3.0.8, Inoperability of Snubbers" (Reference 2). TSTF-372 documents a risk-informed analysis of NonFUNCTIONAL snubbers. The NRC issued a model safety evaluation (Reference 3) providing their acceptance of TSTF-372 with the associated analysis. Probabilistic risk assessment (PRA) results and insights were used, in combination with deterministic and defense-in-depth arguments, to identify and justify delay times for entering the actions for the supported equipment associated with NonFUNCTIONAL snubbers at nuclear power plants. This is in accordance with guidance provided in Regulatory Guides (RGs) 1.174 and 1.177. The risk impact associated with the proposed delay times for entering the TS actions for the supported equipment can be assessed using the same approach as for allowed completion time (CT) extensions. Therefore, the risk assessment was performed following the three-tiered approach recommended in RG 1.177 for evaluating proposed extensions in currently allowed completion times.

The first tier involves the assessment of the change in plant risk due to a NonFUNCTIONAL snubber. Such risk change is expressed by: (1) the change in the average yearly core damage frequency (ΔCDF) and the average yearly large early release frequency (ΔLERF); and, (2) the incremental conditional core damage probability (ICCDP) and the incremental conditional large early release probability (ICLERP).

BASES

BACKGROUND (continued)

The assessed ΔCDF and ΔLERF values are compared to acceptance guidelines, consistent with the Commission's Safety Goal Policy Statement as documented in RG 1.174, so that the plant's average baseline risk is maintained within a minimal range. The assessed ICCDP and ICLERP values are compared to acceptance guidelines provided in RG 1.177, which aim at ensuring that the plant risk does not increase unacceptably during the period the equipment is taken out of service.

This assessment was used to determine the delay times contained in TS LCO 3.0.8 for TSTF-372. Due to the low seismic activity at KPS, the LCO 3.0.8.b completion time was increased from the value listed in TSTF-372.

The second tier involves the identification of potentially high-risk configurations that could exist if equipment in addition to that associated with the change were to be taken out of service simultaneously, or other risk-significant operational factors such as concurrent equipment testing were also involved. The objective is to ensure that appropriate restrictions are in place to avoid any potential high-risk configurations.

This assessment was used to determine the contingency measures in TSTF-372, which are contained in TRM 8.7.5.

The third tier involves the establishment of an overall configuration risk management program (CRMP) to ensure that potentially risk-significant configurations resulting from maintenance and other operational activities are identified. The objective of the CRMP is to manage configuration specific risk by appropriate scheduling of plant activities and/or appropriate compensatory measures. This activity is met by implementation of the Maintenance Rule (Reference 4).

The accident sequences contributing to the risk increase associated with NonFUNCTIONAL snubbers are assumed to be initiated by a seismically induced loss of offsite power (LOOP) event with concurrent loss of all safety system trains supported by the out of service snubbers. In the case of snubbers associated with more than one train (or subsystem) of the same system, it is assumed that all affected trains (or subsystems) of the supported system are failed.

BASES

BACKGROUND (continued)	The risk impact associated with non-LOOP accident sequences (*e.g.*, seismically initiated loss of coolant accident (LOCA) or anticipated transient without scram (ATWS) sequences) was not assessed. However, this risk impact is small compared to the risk impact associated with the LOOP accident sequences modeled in the simplified bounding risk assessment. Therefore, the risk impact of NonFUNCTIONAL snubbers associated with non-LOOP accident sequences is small compared to the risk impact associated with the LOOP accident sequences. The second tier of the three-tiered approach recommended in RG 1.177 involves the identification of potentially high risk configurations that could exist if equipment in addition to that associated with the NonFUNCTIONAL snubbers were to be taken out of service simultaneously. Insights from the risk assessments, in conjunction with important assumptions made in the analysis and defense-in-depth considerations, were used to identify such configurations. To avoid these potentially high risk configurations, specific restrictions on operation with NonFUNCTIONAL snubbers were identified. TRM 8.7.5 is based on these Tier II restrictions.
TNC and APPLICABILITY	To ensure supported system OPERABILITY, each snubber listed in Table 8.7.5-1 is required to be FUNCTIONAL whenever the associated supported system is required to be OPERABLE. If a supported system is not required to be OPERABLE (e.g., outside the TS MODE of Applicability for that system), then its associated snubber is not a required snubber during the period that the supported system is not required to be OPERABLE. For consistency, those snubbers listed in Table 8.7.5-1 that are only associated with a TRM system (e.g., CVCS), are treated within the scope of TRM 8.7.5 applicability (i.e., the terms FUNCTIONAL and OPERABLE for these supported TRM systems are treated synonymously for purposes of TRM 8.7.5 compliance). TRM Table 8.7.5-1 provides a listing of "required snubbers" within the application of LCO 3.0.8. LCO 3.0.8 does not apply to non-seismic snubbers. This table also lists the TS LCOs that are potentially affected by the FUNCTIONALITY of the listed snubbers. Although this table lists the potentially affected TS LCOs, the actual LCOs affected must be confirmed whenever the applicable specified period of LCO 3.0.8 is exceeded. Compliance with the CONTINGENCY MEASURES required by TNC 8.7.5 ensures that the risk associated with NonFUNCTIONAL "required snubbers" is "assessed and managed" as required by LCO 3.0.8.

BASES

TNC and APPLICABILITY (continued)

The list in Table 8.7.5-1 contains those snubbers from the Snubber Test Program that are identified as safety related (QA Type 1). For each listed snubber, Table 8.7.5-1 identifies the type of load support provided by the snubber (seismic or dynamic), systems associated with that snubber, associated TS/TRM section, applicable MODE, and whether the snubber affects a single train or dual trains.

In determining the identified information, the snubbers were located on the associated isometric drawing listed on the snubber table found in the Snubber Test Program. The location was then identified on the related analytical part flow drawing (e.g., snubber RTD-H11 was located on M-1461 and APX-100-10). From this information, the boundaries of the analytical part were determined and affected systems identified. A system was determined to be related if, for a listed Non-FUNCTIONAL snubber, no means of isolating the associated analytical part (i.e., isolated by a component that was outside the analytical part boundary) from the interconnected system was found. Once the affected systems were identified, the applicable TS and MODES were determined. Only internal containment spray (ICS) snubbers inside containment were found to provide dynamic support in addition to seismic support (Reference 5).

A snubber is FUNCTIONAL when it is capable of performing its specified design functions.

Snubbers are classified as component standard supports, which are designed to transmit loads from the pressure-retaining boundary of the system component to the building structure. However, they require special consideration due to their unique function. Snubbers are designed to provide no transmission of force during normal plant operations. Rather, they function as a rigid support only when subjected to dynamic transient loadings. Snubbers are chosen in lieu of rigid supports where restricting thermal growth during normal operation would induce excessive stresses in the piping nozzles or other equipment. The location and size of the snubbers are determined by stress analysis. Depending on the design classification of the particular piping, different combinations of load conditions are established. These conditions combine loading during normal operation, seismic loading and loading due to plant accidents and transients to four different loading sets. These loading sets are designated as: normal, upset, emergency, and faulted conditions. The actual loading included in each of the four conditions depends on the design classification of the piping. These design requirements establish snubber FUNCTIONALITY criteria.

BASES

CONTINGENCY MEASURES

The CONTINGENCY MEASURES are modified by a Note that allows a separate CONTINGENCY MEASURE entry for each NonFUNCTIONAL snubber. This is acceptable because the CONTINGENCY MEASURE for each Nonconformance provides appropriate compensatory actions for each NonFUNCTIONAL snubber.

A.1

TS LCO 3.0.2 and LCO 3.0.6 generally require immediate entry into the supported system Conditions and Required Actions when a snubber is found or made NonFUNCTIONAL. The only exceptions are:

1) Immediate entry may be delayed per LCO 3.0.8; or,

2) The supported system has been analyzed and determined to be OPERABLE without the snubber.

Whenever a required snubber is found or made NonFUNCTIONAL, compliance with LCO 3.0.8 must be evaluated immediately. The requirements of LCO 3.0.2 and LCO 3.0.6 are applicable to this evaluation. If the supported system has been analyzed and determined to be OPERABLE without reliance on the snubber, then the snubber can be considered as not required and LCO 3.0.8 remains satisfied.

TS LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable.

The 72 hour allowance in LCO 3.0.8.a is based, in part, on the availability of the redundant train of the supported system (for multiple train systems) and on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function. This allowance is also applicable to snubbers associated with single train or subsystem supported systems because such single train systems are not required to have a redundant system.

TS LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 24 hours to restore the snubber(s) before declaring the supported system inoperable.

BASES

CONTINGENCY MEASURES (continued)

LCO 3.0.8 requires that risk be assessed and managed when one or more snubbers are NonFUNCTIONAL, which may include compensatory measures for NonFUNCTIONAL snubbers. This is met by assessing and managing the risk in accordance with the Maintenance Rule Program (Reference 4). Additional information on this requirement is contained in the LCO 3.0.8 Bases.

A.2

The risk impact of dynamic loadings other than seismic loads was not assessed in the development of the delay times in LCO 3.0.8. These shock-type (non-seismic) loads include thrust loads, blowdown loads, water hammer loads, steam hammer loads, LOCA loads and pipe rupture loads. In general, the risk impact of the out-of-service snubbers is smaller for non-seismic loads than for seismic loads. Since dynamic loading was not generically assessed for justifying LCO delay times, a specific assessment is required to be performed to determine appropriate system capability based on equipment that may be out of service for maintenance or due to failure.

Therefore, whenever the provisions of LCO 3.0.8 are used, an engineering assessment must immediately be initiated to show that at least one train (or subsystem) of each system that is supported by the NonFUNCTIONAL snubber(s) would remain capable of performing its required safety or support functions for postulated design loads other than seismic loads. This verification must be documented (typically in operator logs).

A train (or subsystem) that is supported by a NonFUNCTIONAL snubber that does not provide dynamic support (as stated in the "Support Loads" column of Table 8.7.5-1) would remain capable of performing its required safety or support function for postulated design loads other than seismic loads (provided it is otherwise capable of performing its required function). This means that a NonFUNCTIONAL snubber that is listed in Table 8.7.5-1 as only providing seismic support (in the "Support Loads" column) remains capable of performing its required support function for purposes of satisfying CONTINGENCY MEASURE A.2.

Conversely, a system supported by a snubber that provides dynamic support would not meet the capability requirement of CONTINGENCY MEASURE A.2 for the train supported by that snubber.

CONTINGENCY MEASURES (continued)

A.3.1

For cases where all NonFUNCTIONAL snubbers are associated with only one train (or subsystem) of multiple train systems (i.e., when LCO 3.0.8.a applies), the analysis assumes that there will be unaffected redundant trains (or subsystems) available to mitigate the seismically initiated LOOP accident sequences (single train systems are not required to have a redundant system). To prevent potentially high risk configurations in this condition, a restriction was established to require at least one AFW train that is not associated with the NonFUNCTIONAL snubber(s).

Thus, when LCO 3.0.8.a is used, at least one AFW train (including a minimum set of supporting equipment required for its successful operation) not associated with the NonFUNCTIONAL snubber(s), must be available.

A.3.2

For cases where one or more of the NonFUNCTIONAL snubbers are associated with multiple trains (or subsystems) of the same safety system (i.e., when LCO 3.0.8.b applies), the bounding analysis assumes that all safety systems are unavailable to mitigate the seismically initiated LOOP accident sequences. Credit is taken for using feed and bleed (F&B) to provide core cooling when a snubber impacting more than one train of the AFW system is NonFUNCTIONAL. To prevent potentially high risk configurations in this condition, a restriction was established to require either, at least one AFW train that is not associated with the NonFUNCTIONAL snubber(s); or, an alternate means of core cooling.

Thus, when LCO 3.0.8.b is used, one of the following two requirements must be met to mitigate a seismically initiated loss of offsite power (LOOP) accident:

1) At least one AFW train (including a minimum set of supporting equipment required for its successful operation) not associated with the NonFUNCTIONAL snubber(s); or,
2) An alternative means of core cooling (e.g., feed and bleed, fire water system or "aggressive secondary cooldown" using the steam generators) must be available.

BASES

CONTINGENCY MEASURES (continued)

B.1

CONTINGENCY MEASURE A.2 requires verification that at least one train (or subsystem) supported by the NonFUNCTIONAL snubber would remain capable of performing its required safety or support function for postulated design loads other than seismic loads. If this requirement is not satisfied, then LCO 3.0.8 cannot be used to delay performing the Required Actions of the supported system LCO. In this case, the support system LCO is not met and the applicable Required Action must be entered immediately in accordance with LCO 3.0.2 and 3.0.6.

C.1 and C.2

CONTINGENCY MEASURE A.3 (i.e., A.3.1 or A.3.2) requires verification of a means of providing core cooling independent of the components directly supported by the NonFUNCTIONAL snubber (either AFW or some alternate means). If another means of providing core cooling cannot be identified or becomes unavailable, the risk must be assessed and managed in accordance with the Maintenance Rule Program (Reference 4), as described in LCO 3.0.8 basis.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.7.5.1

All safety related hydraulic shock suppressors are visually inspected for overall integrity and FUNCTIONALITY. The inspection will include verification of proper orientation, adequate hydraulic fluid level and proper attachment of snubber to piping and structures.

The inspection frequency is based upon maintaining a constant level of snubber protection. Thus the required inspection interval varies with the observed snubber failures. The number of NonFUNCTIONAL snubbers found during a required inspection determines the time interval for the next required inspection.

Experience at operating facilities has shown that the surveillance program should assure an acceptable level of snubber performance provided that the seal materials are compatible with the operating environment.

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)	To further increase the assurance of snubber reliability, FUNCTIONAL tests are performed in accordance with sampling plans. These tests include stroking of the snubbers to verify proper piston movement and snubbing action. Ten percent of the safety-related snubbers represents an adequate sample for such tests. Observed failures on these samples require testing of additional units.
REFERENCES	1. 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. 2. TSTF-372, "Addition of LCO 3.0.8, Inoperability of Snubbers," Revision 4. 3. Federal Register Notice, 70 FR 23252, dated May 4, 2005. 4. 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." 5. USAR Section 6.2.2.3, Protection Against Dynamic Effects.

8.8 ELECTRICAL SYSTEMS

8.8.1 Technical Support Center (TSC) Station Blackout (SBO) Diesel Generator (DG)

TNC 8.8.1 TSC SBO DG shall be FUNCTIONAL with:

a. Usable fuel oil supply ≥ 200 gallons;

b. Lube oil supply within limits; and,

c. Starting battery functional.

APPLICABILITY: At all times.

CONTINGENCY MEASURES

---NOTE---

Changes may be made in plant operational MODES or conditions with the TSC SBO DG NonFUNCTIONAL.

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. TSC SBO DG NonFUNCTIONAL.	A.1 Initiate action to restore to FUNCTIONAL status. AND	Immediately
	A.2.1 If in MODES 1, 2, 3 or 4, protect both emergency dieseÌ€l generators (EDGs). OR	Immediately
	A.2.2 If in MODES 5, 6 or Defueled, protect one EDG. AND	Immediately

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. (continued)	A.3 Protect required offsite power sources.	Immediately
	AND	
	A.4 Protect Bus 1-46.	Immediately
	AND	
	A.5 Ensure dose assessment can be performed from the control room.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.8.1.1	Verify TSC SBO DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 500 kW.	31 days
TVR 8.8.1.2	Verify TSC SBO DG fuel oil storage tank contains ≥ 200 gallons of usable fuel.	31 days
TVR 8.8.1.3	Verify TSC SBO DG lube oil level is ≥ 1 inch below "F" mark on engine oil dipstick when engine has been shutdown > 20 minutes.	31 days
TVR 8.8.1.4	Verify fuel oil properties for water, sediment, and particulates in the TSC SBO DG day tank are tested and maintained within limits.	92 days
TVR 8.8.1.5	Verify TSC SBO DG starts from standby condition in ≤ 40 seconds and achieves required voltage and frequency.	18 months
TVR 8.8.1.6	Verify TSC SBO DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 600 kW.	18 months
TVR 8.8.1.7	Verify TSC SBO DG auto start and load circuitry is FUNCTIONAL.	18 months
TVR 8.8.1.8	--------------------------NOTE------------------------------ Replacing the battery meets this TVR. -- Verify required starting battery capacity.	36 months

BASES

BACKGROUND	The TSC SBO DG is an independent, non-class 1E, 600 kW (1000 hr/year standby rating) power source that provides AC power to 480V Bus 1-46 through breaker 14604. It is also the alternate AC (AAC) power supply for station blackout required by 10 CFR 50.63 (Reference 1), which was implemented using guidance from NUMARC 87-00 (Reference 2), except where NRC Regulatory Guide 1.155 (Reference 3) takes precedence. SBO details are contained in USAR Section 8.2.4 (Reference 4). The TSC SBO DG starts automatically on loss of voltage to Bus 1-46 and automatically connects to the bus after attaining voltage and frequency provided that Source Breaker 14601 has tripped. The TSC SBO DG provides power to the TSC Building, security lighting system, and other non-ESF plant systems which are required to operate upon loss of the main generator and off-site electrical sources. Auxiliaries for fuel supply, engine radiator heat rejection, and ventilation are energized from bus 1-46. The TSC SBO DG can also power the necessary make-up system equipment to maintain adequate reactor coolant system (RCS) inventory to ensure that the core is cooled for the required 4 hour coping duration. The TSC SBO DG does not typically supply power to QA Type 1 equipment. For SBO response, a connection can be made between Bus 1-46 and the 480V Safety Bus 1-52. Normal isolation between the two buses is provided by a Class 1E breaker at Bus 1-52 and a non-Class 1E breaker at Bus 1-46. For SBO, selected non-essential loads will be stripped from each of the two buses and the two breakers will be closed to provide power to essential loads on both buses. The total load to be powered within 1 hour following the onset of the SBO is calculated to be approximately 575 kW. The SBO coping duration for KPS is 4 hours per the NUMARC 87-00 guidelines. This duration is based on an offsite power design characteristic group of "P1," an Emergency AC power configuration group "C," and a target Emergency DG (EDG) reliability of 0.95. The "P1" grouping is based on procedural controls in place to cross-tie Buses 1-5 and 1-6 if normal power to either bus is lost and its associated EDG fails to restore power to the bus (Reference 5).
TNC and APPLICABILITY	The TSC SBO DG is required to be FUNCTIONAL at all times, both to meet its requirement as the AAC power source, and to provide automatic AC power to TSC equipment for Emergency Preparedness (EP) response.

BASES

TNC and APPLICABILITY (continued)

For SBO response, the TSC SBO DG is a minimally capable AAC source that is required to be available within one hour after the onset of SBO. It has sufficient capacity for operation of all systems required for coping with a 4 hour SBO event. The need for a coping assessment is based in part on the fact that this source may not be available within 10 minutes. The TSC SBO DG has adequate capacity, with administrative electrical load controls, for the applied SBO loads.

The TSC SBO DG is FUNCTIONAL when it is capable of meeting both its AAC and TSC supply requirements. Its function as an AAC source requires that it be available, via manual actions, to Bus 1-52 within one hour of the onset of a SBO. It must also be capable of automatically starting and available to power required loads within 30 minutes after loss of power to Bus 1-46 to meet EP activation requirements.

The 10,000 gallon capacity fuel oil storage tank for the TSC SBO DG is maintained with sufficient fuel oil to allow operation at the SBO load output for the 4 hour coping duration (approximately 200 gallons). A minimum indicated level of 2000 gallons is procedurally required to maintain defense in depth beyond the minimum needed for SBO coping and thereby assure that the required 200 gallons of usable fuel is available.

To be FUNCTIONAL, the lube oil supply must be within established quality and quantity limits. Required oil quantity is determined using the engine oil dipstick, which can only be used when the engine is shutdown. Oil level must be ≥ 1 inch below "F" mark on dipstick (i.e., 1 inch below "F" mark is the lowest allowable oil level) when engine has been shutdown > 20 minutes. When the engine is running, proper oil levels are monitored on the oil level sight glass. Oil quality is maintained via normal station processes for lube oil procurement.

The starting battery must be maintained in a high state of readiness to ensure it remains capable of starting the TSC SBO DG in ≤ 40 seconds of a start signal. The battery is connected to a battery charger that maintains it continuously charged.

CONTINGENCY MEASURES

A.1

If the TSC SBO DG is NonFUNCTIONAL, action must immediately be initiated to restore it to FUNCTIONAL status. While it is being restored, the following additional compensatory actions (A.2 thru A.5) are needed to ensure availability of electrical power and the capability to respond to a loss of power event.

CONTINGENCY MEASURES (continued)

A.2.1 and A.2.2

The EDGs provide standby power to each required ESF bus. With the TSC SBO DG NonFUNCTIONAL, additional actions are required to ensure availability of the required EDGs. Administrative controls must immediately be initiated to prevent activities that would unnecessarily degrade the availability of any EDG required to be OPERABLE (e.g., planned maintenance, testing, etc.)

A.3

With the TSC SBO DG NonFUNCTIONAL, the availability of AC power is degraded. Actions must immediately be initiated to protect the circuits that supply required offsite power to the onsite electrical distribution system. Do not perform planned work on any of the following high voltage electrical distribution equipment:

Tertiary Auxiliary Transformer (TAT) and the Reserve Auxiliary Transformer (RAT), TAT Supply Transformer and RAT Supply Transformer (including load tap changers), switchyard equipment, and transmission and substation equipment/components in the relay house (e.g., protective relaying, fault detection, etc.).

A.4

With the TSC SBO DG NonFUNCTIONAL, the power supply to Bus 1-46 is degraded. Except for emergent circumstances, work and testing relative to Bus 46 should not be undertaken.

A.5

From an EP perspective, including probabilistic risk assessment insight, with the TSC SBO DG out of service, the intent of the compensatory and mitigation measures is to:

- Have adequate measures in place to minimize the probability of creation of a loss-of-power event.
- Have adequate measures in place to deal with an event requiring activation and manning of the TSC, preceded by or followed by a loss of offsite power, rendering the TSC NonFUNCTIONAL.

BASES

CONTINGENCY MEASURES (continued)

During the time the TSC diesel is NonFUNCTIONAL, if the emergency response organization is activated and there is a loss of offsite power to the TSC, it may be necessary to relocate the TSC due to loss of the TSC ventilation and loss of the ability to acquire data. If it becomes necessary to relocate the TSC, the following functions/activities are covered by the Emergency Plan Implementing Procedures:

- Communications/notifications will be performed from the Control Room until the emergency operations facility (EOF) is activated.
- Classification will be maintained in the Control Room.
- Protective Action Recommendations will be maintained in the Control Room until the EOF is activated.
- Dose assessment will be performed from the Control Room until the EOF is activated.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.8.1.1

NUMARC 87-00 (Paragraph B.10) specifies that the AAC source shall be started and brought to operating conditions that are consistent with its function as an AAC source at intervals not longer than three months, following manufacturer's recommendations or in accordance with plant developed procedures. Verifying that the TSC SBO DG is synchronized with its bus, loaded, and operates for ≥ 60 minutes at a load ≥ 500 kW meets this guidance. The 31 day frequency is more conservative than the guidance, which is acceptable.

TVR 8.8.1.2

Required usable fuel oil quantity is verified by checking indicated level on the TSC SBO DG fuel oil storage tank. The 200 gallon limit is based on the fuel needed for operation at the SBO load output for the 4 hour coping duration. However, a minimum indicated level of 2000 gallons is procedurally required to assure that the required 200 gallons of usable fuel is available. This verification is typically performed in conjunction with DG load testing. This TVR is satisfied if indicated level is ≥ 2000 gallons or if 200 usable gallons is otherwise determined. The 31 day frequency is adequate to ensure that a sufficient supply of usable fuel oil is available, since unit operators would be aware of any large uses of fuel oil during this period.

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

TVR 8.8.1.3

Required lube oil quantity is verified by checking that level does not decrease lower than 1 inch below "F" mark on engine oil dipstick when engine has been shutdown > 20 minutes. This verification is typically performed in conjunction with DG load testing. The 31 day frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by unit staff.

TVR 8.8.1.4

License Renewal Commitment 30 (Reference 6) requires that quarterly laboratory testing of fuel oil samples for water, sediment, and particulates will be performed on the emergency diesel generator (EDG) day tanks and on the technical support center diesel generator (TSC DG) day tank. TVR 8.8.1.4 addresses the TSC DG portion of this commitment. The testing acceptance criteria will be consistent with the requirements specified in American Society for Testing and Materials (ASTM) D975-06b for water and sediment and ASTM D6217 (D6217-98) for particulates.

Fuel oil in the TSC DG day tank shall be sampled for water and sediment on a quarterly (92-day) basis in accordance with ASTM D975-06b.

Particulate concentrations shall be determined on a quarterly (92-day) basis in accordance with ASTM D6217. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a maximum limit of 10 mg/l. ASTM D6217 provides the sample analysis methodology and states that the corresponding particulate limits are as specified in several military fuel specifications (which provide a maximum limit for particulate content of 10 mg/l). The particulate limit of 10 mg/l is consistent with the sampling requirements in ASTM D6217. NRC Information Notice (IN) 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems," had identified that certain earlier testing methods were inappropriate. IN 91-46 stated that the particulate contamination test of ASTM-D2276 was an appropriate test for particulate contamination of stored fuel oil and discussed a limit of 10 mg/l. ASTM-D2276 was supplemented by ASTM-D6217 (Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration) because it is more appropriate for Number 2 diesel fuel. This method is also consistent with EPRI NP-6317.

TECHNICAL VERIFICATION REQUIREMENTS (continued)

TVR 8.8.1.5

NUMARC 87-00 (Paragraph B.10) specifies that a timed start (within the time period specified under blackout conditions) shall be performed once every refueling outage. Verifying the TSC SBO DG starts from standby condition in ≤ 40 seconds and achieves required voltage and frequency meets this criterion. The 18 month frequency is consistent with the normal periodicity of refueling outages at KPS.

TVR 8.8.1.6

NUMARC 87-00 (Paragraph B.10) specifies that a rated load capacity test shall be performed once every refueling outage. Verifying that the TSC SBO DG is synchronized with its bus, loaded, and operates for ≥ 60 minutes at a load ≥ 600 kW meets this guidance. The 18 month frequency is consistent with the normal periodicity of refueling outages at KPS.

TVR 8.8.1.7

This TVR ensures that the auto start and load circuitry is capable of supporting the TSC SBO DG function to provide automatic emergency power to TSC equipment for EP response. This verification is only performed on the associated circuitry components (auto loading of the DG onto the bus is not required to be performed as part of the test).

TVR 8.8.1.8

Every 36 months, the starting battery must be either replaced with a new battery or tested to verify that it maintains required capacity needed to start the TSC SBO DG in ≤ 40 seconds. Battery replacement is typically performed rather than capacity testing based on economics (i.e., cost). The 36 month frequency is based on the vendor's recommendation contained in a letter from the engine manufacturer, Western Engine (Reference 7).

BASES

REFERENCES

1. 10 CFR 50.63, Loss of All Alternating Current Power.
2. NUMARC 87-00 (Rev 0), Appendix B, Alternate AC Power Criteria.
3. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.155, Station Blackout, August 1988.
4. USAR Section 8.2.4, Station Blackout.
5. NRC Supplemental Safety Evaluation Report, A. G. Hansen (NRC) to C. A. Schrock (WPS), Letter No. K-92-215, November 19, 1992.
6. KPS Renewed Facility Operating License, § 2.C(15)(b), NUREG-1958, "Safety Evaluation Report Related to the Kewaunee Power Station," Appendix A, dated January 2011, License Renewal Commitment 30.
7. Commitment 95-090, Periodic Capacity Testing of the TSC SBO Diesel Starting Batteries per Letter from Western Engine dated July 26, 1996.

8.8 ELECTRICAL SYSTEMS

8.8.2 AC Sources

TNC 8.8.2

a. At least one pair of physically independent lines serving the substation shall be FUNCTIONAL:

1. R-304 and Q-303
2. F-84 and Y-51
3. R-304 and Y-51

b. Specified Emergency Diesel Generator (EDG) support activities shall be met.

APPLICABILITY: MODES 1 and 2 (TNC 8.8.2.a);
Whenever the associated EDG is required to be OPERABLE (TNC 8.8.2.b)

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. TNC 8.8.2.b not met.	A.1 Enter TNC 7.5.3.	Immediately
	<u>AND</u>	
	A.2 Evaluate OPERABILITY of EDG(s) per Technical Specification 3.8.1 and 3.8.2.	Immediately
B. TNC 8.8.2.a not met.	B.1 Verify two transmission lines serving substation are FUNCTIONAL.	Immediately
	<u>AND</u>	
	B.2 Restore one of the three listed pairs of transmission lines to FUNCTIONAL status.	7 days

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
C. Three offsite power supply lines NonFUNCTIONAL.	C.1 Initiate action to reduce reactor power to 50% of rated power.	Immediately
	<u>AND</u>	
	C.2 Test both EDGs.	Every 24 hours
	<u>AND</u>	
	C.3 Evaluate OPERABILITY of AC Source per Technical Specification 3.8.1.	Immediately
	<u>AND</u>	
	C.4 Restore one offsite power supply line to FUNCTIONAL status.	7 days
D. CONTINGENCY MEASURE and associated Restoration Time of Condition B or C not met.	D.1 Evaluate OPERABILITY of AC Source per Technical Specification 3.8.1.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.8.2.1	Verify at least one pair of physically independent transmission lines serving the substation is FUNCTIONAL.	7 days
TVR 8.8.2.2	For each EDG, verify fuel oil properties for water, sediment, and particulates in the EDG day tank are tested and maintained within limits.	92 days
TVR 8.8.2.3	Perform NACE surveys of the cathodic protection system associated with the fuel oil storage tanks and protected portions of the fuel oil lines.	12 months
TVR 8.8.2.4	For each EDG, perform inspection in accordance with procedures prepared in conjunction with its manufacture's recommendations.	18 months

BASES

BACKGROUND

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions (Reference 1).

Plant safeguards auxiliary power is normally supplied by two separate external power sources which have multiple off-site network connections (Reference 2): the reserve auxiliary transformer and the tertiary auxiliary transformer. Either source is sufficient to supply all necessary accident and post-accident load requirements from any one of four available transmission lines.

The requirements for offsite transmission line pairs and for performance of EDG inspections were relocated from the previous Custom Technical Specifications (TS) 3.7.a.8 and TS 4.6.1.3, respectively, during the conversion to Improved TS in License Amendment 207 (Reference 3).

TNC and APPLICABILITY

Offsite power is supplied to the unit substation from the transmission network by four transmission lines. These four transmission lines support OPERABILITY of the two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System (TS LCO 3.8.1.a). To perform this support function, at least one pair of physically independent transmission lines serving the substation must be FUNCTIONAL. Any one of the following transmission line pairs satisfies this requirement:

R-304 and Q-303;
F-84 and Y-51; or,
R-304 and Y-51.

The physical routing of these lines eliminates the possibility of one line causing failure in three lines (Reference 4), since the lines in these pairs do not cross each other. The physical independence of the F-84 and Y-51 pair is based upon the assumption that a catastrophic failure of line Q-303 will not be extended past Dead-end Tower No. 10; and therefore, would only affect one of the two lines. With any of the three specified line pairs FUNCTIONAL, one line would continue to remain FUNCTIONAL following any postulated single line failure.

To be FUNCTIONAL, each line in a transmission line pair must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the qualified

BASES

TNC and APPLICABILITY (continued)	circuits required by LCO 3.8.1.a. Predicted post trip grid voltage must be capable of being maintained above required values for the associated circuit. Real time voltage on the 138 kV lines must be within 124 kV and 151 kV. Grid frequency supplying Bus 5 or Bus 6 must be ≥ 59.5 Hz. Extended operation with grid frequency above 60.7 Hz is undesirable due to the potential for individual electrical protective devices to trip. The requirement for transmission line pairs was relocated from the previous Custom TS. They are required to be FUNCTIONAL in Modes 1 and 2, consistent with the previous requirement. To ensure EDG reliability, activities specified by Technical Verification Requirements TVR 8.8.2.2, TVR 8.8.2.3, and TVR 8.8.2.4 must be met whenever the associated EDG is required to be OPERABLE.
CONTINGENCY MEASURES	<u>A.1 and A.2</u> If the Emergency Diesel Generator (EDG) support activities required by TNC 8.8.2.b are not met, the reliability of the associated EDG may be adversely affected. In response, CONTINGENCY MEASURE A.1 requires initiating the action specified in TNC 7.5.3 immediately. This action provides for transition to TNC 7.5.3 to address the condition. Failure to meet a specified EDG support activity does not necessarily render the associated EDG inoperable. However, because such a failure has the potential to adversely affect EDG performance, CONTINGENCY MEASURE A.2 requires that an evaluation be immediately initiated to determine whether this condition has impacted EDG operability. <u>B.1 and B.2</u> If none of the three listed pairs of transmission lines are FUNCTIONAL (i.e., TNC 8.8.2.a is not met), reliability of the normal power supply to emergency equipment is degraded. However, electrical supply redundancy can continue to be maintained if any two transmission lines are serving the substation (e.g., Y-51 and Q-303; F-84 and Q-303; or, F-84 and R-304). Therefore, CONTINGENCY MEASURE B.1 requires immediate action to verify that any two of the four transmission lines serving the substation are FUNCTIONAL.

BASES

CONTINGENCY MEASURES (continued)

When the switchyard is only being supplied by a non-preferred line pair, certain postulated single line failures could result in loss of both lines supplying the switchyard. Such a condition results in a lower level of reliability than would be provided by one of the three required line pairs. Therefore, operation in such a condition is limited in duration by CONTINGENCY MEASURE B.2. Compliance with TNC 8.8.2.a must be restored (by restoring one of the three required pairs of transmission lines to FUNCTIONAL status) within 7 days.

C.1, C.2, C.3, and C.4

If three offsite power supply lines are Nonfunctional, the normal power supply to station emergency equipment is significantly degraded. Loss of the remaining line would result in loss of capability to transfer generated electrical energy to the transmission grid. Immediate action is needed to initiate reactor power reduction to 50% of rated power. The steam dump and turbine electro-hydraulic control systems can accommodate a 50 percent load rejection to auxiliary load using condenser dump without reactor or turbine trip. Operating at or below 50% of rated power in this condition can prevent a reactor or turbine trip in the event of a line loss and enhances transmission system reliability.

Since normal electrical power supply is degraded, verification of the availability of the EDGs is performed at an increased frequency (every 24 hours). The test of the EDG shall be manually starting each diesel generator from a standby condition verifying that each diesel generator achieves steady state voltage and frequency. Refer to SR 3.8.1.2.

With only one of the four offsite power supply lines FUNCTIONAL, redundancy of the normal power supply to station emergency equipment is adversely affected. Therefore, CONTINGENCY MEASURE C.3 requires that an evaluation be immediately initiated to determine whether this condition has impacted operability of either of the two qualified circuits between the offsite transmission network and the onsite electrical system required by TS LCO 3.8.1.a.

CONTINGENCY MEASURE C.4 limits operation with three offsite power supply lines Nonfunctional to a maximum period of 7 days. One additional offsite power supply line must be restored within this period (at least two offsite transmission lines serving the substation must be FUNCTIONAL to satisfy CONTINGENCY MEASURE C.4). Nonconformance B continues to apply in this condition if the two Functional lines do not comprise one of the pairs listed in TNC 8.8.2.a.

BASES

CONTINGENCY MEASURES (continued)

D.1

Nonconformance D applies when the CONTINGENCY MEASURE and associated completion time of Condition B or C is not met. CONTINGENCY MEASURE D.1 requires that an evaluation be immediately initiated to determine whether this condition has impacted operability of either of the two qualified circuits between the offsite transmission network and the onsite electrical system required by TS LCO 3.8.1.a.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.8.2.1

At least one of the three listed pairs of physically independent transmission lines serving the substation must be verified FUNCTIONAL every 7 days.

TVR 8.8.2.2

License Renewal Commitment 30 (Reference 5) requires that quarterly laboratory testing of fuel oil samples for water, sediment, and particulates will be performed on the emergency diesel generator (EDG) day tanks and on the technical support center diesel generator (TSC DG) day tank. TVR 8.8.2.2 addresses the EDG portion of this commitment. The testing acceptance criteria will be consistent with the requirements specified in American Society for Testing and Materials (ASTM) D975-06b for water and sediment and ASTM D6217 for particulates.

Fuel oil in the EDG day tanks shall be sampled for water and sediment on a quarterly (92-day) basis in accordance with ASTM D975-06b.

Particulate concentrations shall be determined on a quarterly (92-day) basis in accordance with ASTM D6217. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a maximum limit of 10 mg/l. ASTM D6217 provides the sample analysis methodology and states that the corresponding particulate limits are as specified in several military fuel specifications (which provide a maximum limit for particulate content of 10 mg/l). The particulate limit of 10 mg/l is consistent with the sampling requirements in ASTM D6217. NRC Information Notice (IN) 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems," had identified that certain earlier testing methods were inappropriate. IN 91-46 stated that the particulate contamination test of ASTM-D2276 was an

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

appropriate test for particulate contamination of stored fuel oil and discussed a limit of 10 mg/l. ASTM-D2276 was supplemented by ASTM-D6217 (Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration) because it is more appropriate for Number 2 diesel fuel. This method is also consistent with EPRI NP-6317.

TVR 8.8.2.3

License Renewal Commitment 48 (Reference 5) states that the cathodic protection system associated with the diesel generator fuel oil storage tanks and protected portions of the fuel oil lines will each be maintained available a minimum of 90% of the time during the period of extended operation (starting December 22, 2013). In addition, National Association of Corrosion Engineers (NACE) cathodic protection system surveys will be performed at least annually during the period of extended operation.

This verification addresses the cathodic protection survey requirements associated with the EDG aspect of this commitment.

TVR 8.8.2.4

EDG inspections are performed at refueling outage intervals in order to maintain the diesel generators in accordance with the manufacturers' recommendations. The inspection procedure is periodically updated to reflect experience gained from past inspections and new information as it is available from the manufacturer.

REFERENCES

1. USAR 8.1.1.2.1
2. USAR Figure 8.2-1 and 8.2-2
3. 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.
4. NRC Safety Evaluation Related to License Amendment 67, dated July 3, 1986.
5. KPS Renewed Facility Operating License, § 2.C(15)(b), NUREG-1958, "Safety Evaluation Report Related to the Kewaunee Power Station," Appendix A, dated January 2011, License Renewal Commitments 30 and 48.

8.8 ELECTRICAL SYSTEMS

8.8.2 AC Sources

TNC 8.8.2

a. At least one pair of physically independent lines serving the substation shall be FUNCTIONAL:

1. R-304 and Q-303
2. F-84 and Y-51
3. R-304 and Y-51

b. Specified Emergency Diesel Generator (EDG) support activities shall be met.

APPLICABILITY: MODES 1 and 2 (TNC 8.8.2.a);
Whenever the associated EDG is required to be OPERABLE (TNC 8.8.2.b)

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. TNC 8.8.2.b not met.	A.1 Enter TNC 7.5.3.	Immediately
	<u>AND</u>	
	A.2 Evaluate OPERABILITY of EDG(s) per Technical Specification 3.8.1 and 3.8.2.	Immediately
B. TNC 8.8.2.a not met.	B.1 Verify two transmission lines serving substation are FUNCTIONAL.	Immediately
	<u>AND</u>	
	B.2 Restore one of the three listed pairs of transmission lines to FUNCTIONAL status.	7 days

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
C. Three offsite power supply lines NonFUNCTIONAL.	C.1 Initiate action to reduce reactor power to 50% of rated power.	Immediately
	AND	
	C.2 Test both EDGs.	Every 24 hours
	AND	
	C.3 Evaluate OPERABILITY of AC Source per Technical Specification 3.8.1.	Immediately
	AND	
	C.4 Restore one offsite power supply line to FUNCTIONAL status.	7 days
D. CONTINGENCY MEASURE and associated Restoration Time of Condition B or C not met.	D.1 Evaluate OPERABILITY of AC Source per Technical Specification 3.8.1.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.8.2.1	Verify at least one pair of physically independent transmission lines serving the substation is FUNCTIONAL.	7 days
TVR 8.8.2.2	For each EDG, verify fuel oil properties for water, sediment, and particulates in the EDG day tank are tested and maintained within limits.	92 days
TVR 8.8.2.3	Perform NACE surveys of the cathodic protection system associated with the fuel oil storage tanks and protected portions of the fuel oil lines.	12 months
TVR 8.8.2.4	For each EDG, perform inspection in accordance with procedures prepared in conjunction with its manufacture's recommendations.	24 months

BASES

BACKGROUND

Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions (Reference 1).

Plant safeguards auxiliary power is normally supplied by two separate external power sources which have multiple off-site network connections (Reference 2): the reserve auxiliary transformer and the tertiary auxiliary transformer. Either source is sufficient to supply all necessary accident and post-accident load requirements from any one of four available transmission lines.

The requirements for offsite transmission line pairs and for performance of EDG inspections were relocated from the previous Custom Technical Specifications (TS) 3.7.a.8 and TS 4.6.1.3, respectively, during the conversion to Improved TS in License Amendment 207 (Reference 3).

TNC and APPLICABILITY

Offsite power is supplied to the unit substation from the transmission network by four transmission lines. These four transmission lines support OPERABILITY of the two qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Power System (TS LCO 3.8.1.a). To perform this support function, at least one pair of physically independent transmission lines serving the substation must be FUNCTIONAL. Any one of the following transmission line pairs satisfies this requirement:

R-304 and Q-303;
F-84 and Y-51; or,
R-304 and Y-51.

The physical routing of these lines eliminates the possibility of one line causing failure in three lines (Reference 4), since the lines in these pairs do not cross each other. The physical independence of the F-84 and Y-51 pair is based upon the assumption that a catastrophic failure of line Q-303 will not be extended past Dead-end Tower No. 10; and therefore, would only affect one of the two lines. With any of the three specified line pairs FUNCTIONAL, one line would continue to remain FUNCTIONAL following any postulated single line failure.

To be FUNCTIONAL, each line in a transmission line pair must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the qualified

BASES

TNC and APPLICABILITY (continued)	circuits required by LCO 3.8.1.a. Predicted post trip grid voltage must be capable of being maintained above required values for the associated circuit. Real time voltage on the 138 kV lines must be within 124 kV and 151 kV. Grid frequency supplying Bus 5 or Bus 6 must be ≥ 59.5 Hz. Extended operation with grid frequency above 60.7 Hz is undesirable due to the potential for individual electrical protective devices to trip. The requirement for transmission line pairs was relocated from the previous Custom TS. They are required to be FUNCTIONAL in Modes 1 and 2, consistent with the previous requirement. To ensure EDG reliability, activities specified by Technical Verification Requirements TVR 8.8.2.2, TVR 8.8.2.3, and TVR 8.8.2.4 must be met whenever the associated EDG is required to be OPERABLE.
CONTINGENCY MEASURES	<u>A.1 and A.2</u> If the Emergency Diesel Generator (EDG) support activities required by TNC 8.8.2.b are not met, the reliability of the associated EDG may be adversely affected. In response, CONTINGENCY MEASURE A.1 requires initiating the action specified in TNC 7.5.3 immediately. This action provides for transition to TNC 7.5.3 to address the condition. Failure to meet a specified EDG support activity does not necessarily render the associated EDG inoperable. However, because such a failure has the potential to adversely affect EDG performance, CONTINGENCY MEASURE A.2 requires that an evaluation be immediately initiated to determine whether this condition has impacted EDG operability. <u>B.1 and B.2</u> If none of the three listed pairs of transmission lines are FUNCTIONAL (i.e., TNC 8.8.2.a is not met), reliability of the normal power supply to emergency equipment is degraded. However, electrical supply redundancy can continue to be maintained if any two transmission lines are serving the substation (e.g., Y-51 and Q-303; F-84 and Q-303; or, F-84 and R-304). Therefore, CONTINGENCY MEASURE B.1 requires immediate action to verify that any two of the four transmission lines serving the substation are FUNCTIONAL.

BASES

CONTINGENCY MEASURES (continued)

When the switchyard is only being supplied by a non-preferred line pair, certain postulated single line failures could result in loss of both lines supplying the switchyard. Such a condition results in a lower level of reliability than would be provided by one of the three required line pairs. Therefore, operation in such a condition is limited in duration by CONTINGENCY MEASURE B.2. Compliance with TNC 8.8.2.a must be restored (by restoring one of the three required pairs of transmission lines to FUNCTIONAL status) within 7 days.

C.1, C.2, C.3, and C.4

If three offsite power supply lines are Nonfunctional, the normal power supply to station emergency equipment is significantly degraded. Loss of the remaining line would result in loss of capability to transfer generated electrical energy to the transmission grid. Immediate action is needed to initiate reactor power reduction to 50% of rated power. The steam dump and turbine electro-hydraulic control systems can accommodate a 50 percent load rejection to auxiliary load using condenser dump without reactor or turbine trip. Operating at or below 50% of rated power in this condition can prevent a reactor or turbine trip in the event of a line loss and enhances transmission system reliability.

Since normal electrical power supply is degraded, verification of the availability of the EDGs is performed at an increased frequency (every 24 hours). The test of the EDG shall be manually starting each diesel generator from a standby condition verifying that each diesel generator achieves steady state voltage and frequency. Refer to SR 3.8.1.2.

With only one of the four offsite power supply lines FUNCTIONAL, redundancy of the normal power supply to station emergency equipment is adversely affected. Therefore, CONTINGENCY MEASURE C.3 requires that an evaluation be immediately initiated to determine whether this condition has impacted operability of either of the two qualified circuits between the offsite transmission network and the onsite electrical system required by TS LCO 3.8.1.a.

CONTINGENCY MEASURE C.4 limits operation with three offsite power supply lines Nonfunctional to a maximum period of 7 days. One additional offsite power supply line must be restored within this period (at least two offsite transmission lines serving the substation must be FUNCTIONAL to satisfy CONTINGENCY MEASURE C.4). Nonconformance B continues to apply in this condition if the two Functional lines do not comprise one of the pairs listed in TNC 8.8.2.a.

BASES

CONTINGENCY MEASURES (continued)

D.1

Nonconformance D applies when the CONTINGENCY MEASURE and associated completion time of Condition B or C is not met. CONTINGENCY MEASURE D.1 requires that an evaluation be immediately initiated to determine whether this condition has impacted operability of either of the two qualified circuits between the offsite transmission network and the onsite electrical system required by TS LCO 3.8.1.a.

TECHNICAL VERIFICATION REQUIREMENTS

TVR 8.8.2.1

At least one of the three listed pairs of physically independent transmission lines serving the substation must be verified FUNCTIONAL every 7 days.

TVR 8.8.2.2

License Renewal Commitment 30 (Reference 5) requires that quarterly laboratory testing of fuel oil samples for water, sediment, and particulates will be performed on the emergency diesel generator (EDG) day tanks and on the technical support center diesel generator (TSC DG) day tank. TVR 8.8.2.2 addresses the EDG portion of this commitment. The testing acceptance criteria will be consistent with the requirements specified in American Society for Testing and Materials (ASTM) D975-06b for water and sediment and ASTM D6217 for particulates.

Fuel oil in the EDG day tanks shall be sampled for water and sediment on a quarterly (92-day) basis in accordance with ASTM D975-06b.

Particulate concentrations shall be determined on a quarterly (92-day) basis in accordance with ASTM D6217. This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a maximum limit of 10 mg/l. ASTM D6217 provides the sample analysis methodology and states that the corresponding particulate limits are as specified in several military fuel specifications (which provide a maximum limit for particulate content of 10 mg/l). The particulate limit of 10 mg/l is consistent with the sampling requirements in ASTM D6217. NRC Information Notice (IN) 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems," had identified that certain earlier testing methods were inappropriate. IN 91-46 stated that the particulate contamination test of ASTM-D2276 was an

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

appropriate test for particulate contamination of stored fuel oil and discussed a limit of 10 mg/l. ASTM-D2276 was supplemented by ASTM-D6217 (Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration) because it is more appropriate for Number 2 diesel fuel. This method is also consistent with EPRI NP-6317.

TVR 8.8.2.3

License Renewal Commitment 48 (Reference 5) states that the cathodic protection system associated with the diesel generator fuel oil storage tanks and protected portions of the fuel oil lines will each be maintained available a minimum of 90% of the time during the period of extended operation (starting December 22, 2013). In addition, National Association of Corrosion Engineers (NACE) cathodic protection system surveys will be performed at least annually during the period of extended operation.

This verification addresses the cathodic protection survey requirements associated with the EDG aspect of this commitment.

TVR 8.8.2.4

EDG inspections are performed at 24 month intervals in order to maintain the diesel generators in accordance with the manufacturers' recommendations. The inspection procedure is periodically updated to reflect experience gained from past inspections and new information as it is available from the manufacturer.

REFERENCES

1. USAR 8.1.1.2.1
2. USAR Figure 8.2-1 and 8.2-2
3. 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.
4. NRC Safety Evaluation Related to License Amendment 67, dated July 3, 1986.
5. KPS Renewed Facility Operating License, § 2.C(15)(b), NUREG-1958, "Safety Evaluation Report Related to the Kewaunee Power Station," Appendix A, dated January 2011, License Renewal Commitments 30 and 48.

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 in each required air cylinder and air leakage downstream of isolation check valve shall be maintained within limits specified in Figure 8.8.3-1.

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

CONTINGENCY MEASURES

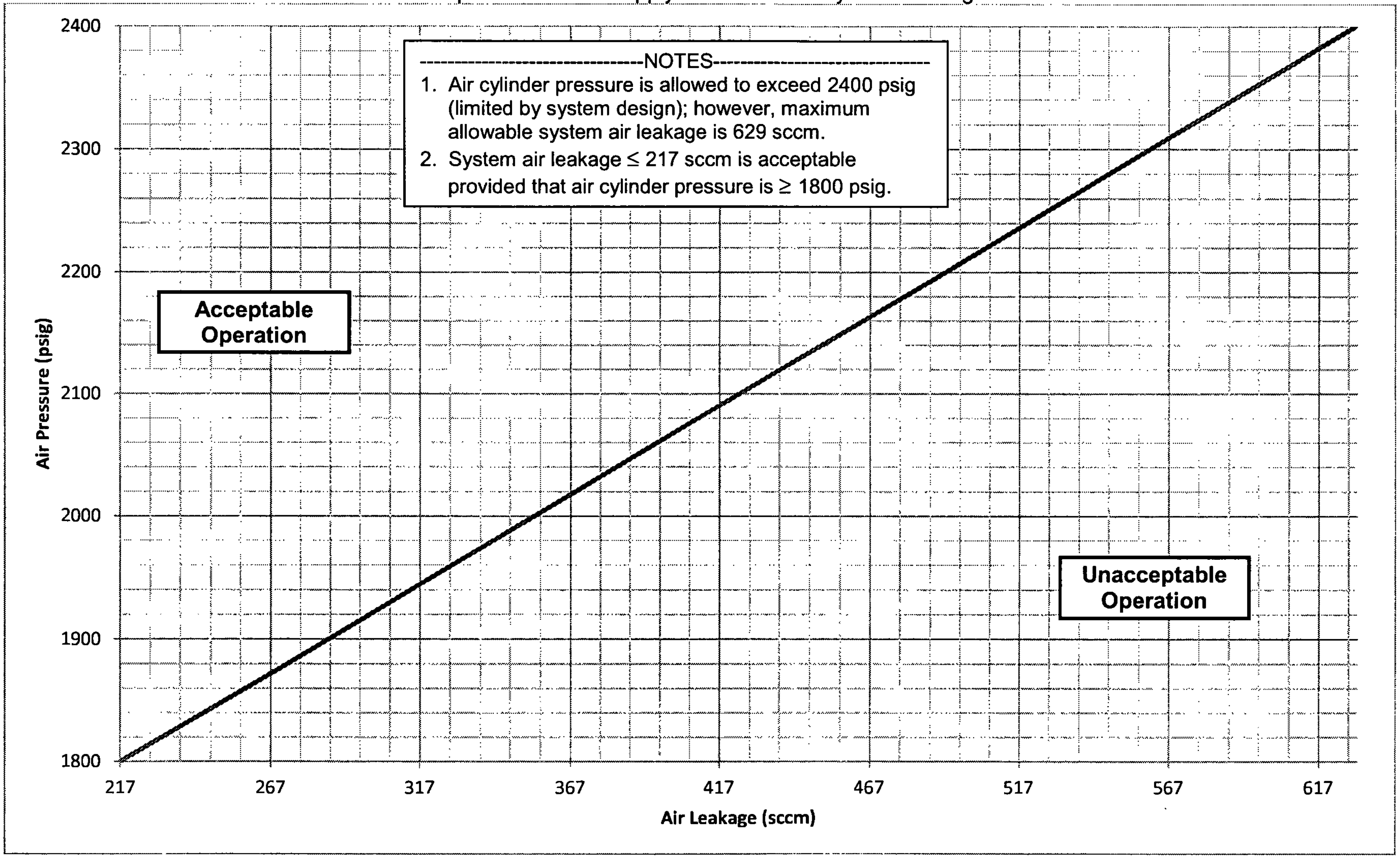
NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
A. Ventilation damper control air supply on one EDG NonFUNCTIONAL for reasons other than Nonconformance B or C.	A.1 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	Immediately
B. Requirements of TNC 8.8.3.b not met on one EDG.	B.1 Restore parameter(s) to within limits. <u>AND</u> B.2 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	24 hours Immediately

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
C. Pressure < 1800 psig in one or more required air cylinders on one EDG.	C.1 Restore air cylinder pressure ≥ 1800 psig. AND C.2 Evaluate OPERABILITY of affected EDG per Technical Specification 3.8.1 and 3.8.2.	4 hours Immediately
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 ≥ pressure limits specified in Figure 8.8.3-1 for the existent air leakage downstream of isolation check valve.	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 specified in Figure 8.8.3-1. --	
	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

Figure 8.8.3-1
EDG Ventilation Damper Control Air Supply Pressure and System Leakage Limitation Curve



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 design 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 (references 3 and 4).

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 and corresponding pressure limits are specified in Figure 8.8.3-1 (and in procedures). Maximum allowable air system leakage varies depending on actual air cylinder pressure. The pressure and leakage limits specified in Figure 8.8.3-1 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 629 sccm with air cylinder pressure at 2400 psig.

Cylinder air pressure and system air leakage must be maintained in the Acceptable Operation portion of the limitation curve of Figure 8.8.3-1. This figure is modified by two Notes. Note 1 permits operation with cylinder air pressure above 2400 psig, provided air leakage is ≤ 629 sccm. Air pressure above 2400 psig results in a larger supply of air and is acceptable. The maximum allowable pressure is limited by system design and is administratively controlled. However, air leakage above 629 sccm indicates unacceptable system degradation and is not allowed. Such excessive leakage must be addressed in accordance with Nonconformance B. Note 2 permits operation with air leakage ≤ 217 sccm, provided cylinder air pressure is ≥ 1800 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.

BASES

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.

B.1 and B.2

If system leakage in the ventilation damper control air supply flow path downstream of the isolation check valve on one EDG exceeds limits specified in Figure 8.8.3-1, 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 (or to raise air pressure to within limits if leakage ≤ 629 sccm).

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 (or raise air pressure as appropriate). 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

BASES

CONTINGENCY MEASURES (continued)

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 and 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 significantly 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 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). Nonconformance C provides defense in depth to the limits specified in Figure 8.8.3-1 against loss of required air supply.

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 in the required (aligned) air cylinders is ≥ minimum required pressure specified in Figure 8.8.3-1, corresponding to the existent air leakage downstream of isolation check valve, 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 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 instrument air isolation check valve, is ≤ 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 system air leakage is within limits specified in Figure 8.8.3-1. 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, Figure 8.8.3-1 allows a minimum cylinder air pressure of 1800 psig. Therefore, leakage should not normally exceed 217 sccm. Leakage that exceeds 217 sccm, although allowed by Figure 8.8.3-1, is not desired long term. Undesired leakage would be addressed via the corrective action (or other appropriate) process.

The minimum required cylinder air pressure corresponding to the existent system air leakage (per Figure 8.8.3-1) must be administratively maintained (e.g., if system air leakage is 355 sccm, then a required minimum cylinder air pressure of 2000 psig must be administratively maintained).

BASES

TECHNICAL VERIFICATION REQUIREMENTS (continued)

TVR 8.8.3.4

Verification that instrument air 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
3. Design Change KW-10-01101, EDG Ventilation Air Supply Modification
4. Calculation C11965

8.8 ELECTRICAL SYSTEMS

8.8.4 Reserve Auxiliary Transformer (RAT) / Reserve Supply Transformer (RST) and Tertiary Auxiliary Transformer (TAT) / Tertiary Supply Transformer (TST)

TNC 8.8.4 The following AC electrical sources shall be FUNCTIONAL:

a. RAT / RST;

AND

b. TAT / TST

APPLICABILITY: Whenever the main generator is in operation

CONTINGENCY MEASURES

NONCONFORMANCE	CONTINGENCY MEASURES		RESTORATION TIME
A. Main feedwater pump (FWP) trip on fast bus transfer circuit unavailable when both FWPs are operating.	A.1	IF RST load tap changer (LTC) is in manual operation, then declare the offsite circuit associated with the RAT inoperable per Technical Specification (TS) 3.8.1.	Immediately
		OR	
	A.2	IF RST LTC is in automatic operation with Delta-V (%) above 0.45%, then declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES	RESTORATION TIME
B. Automatic RST LTC operation with Delta-V (%) monitoring capability unavailable.	B.1 Operate RST LTC in manual. AND B.2 Evaluate OPERABILITY of the offsite circuit associated with the RAT per TS 3.8.1.	Immediately Immediately
C. Automatic TST LTC operation with Delta-V (%) monitoring capability unavailable.	C.1 Operate TST LTC in manual. AND C.2 Evaluate OPERABILITY of the offsite circuit associated with the TAT per TS 3.8.1.	Immediately Immediately
D. Automatic RST LTC operation with Delta-V (%) above 1.2%, while Buses 1-3 AND 1-4 are aligned to the main auxiliary transformer.	D.1 Declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately
E. Automatic RST LTC operation with Delta-V (%) above 2.7%, while Bus 1-3 OR Bus 1-4 is aligned to the RAT.	E.1 Declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately
F. Automatic RST LTC operation with Delta-V (%) above 4.5%, while Buses 1-3 AND 1-4 are aligned to the RAT.	F.1 Declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately
G. Automatic TST LTC operation with Delta-V (%) above 5.0%.	G.1 Declare the offsite circuit associated with the TAT inoperable per TS 3.8.1.	Immediately

CONTINGENCY MEASURES (continued)

NONCONFORMANCE	CONTINGENCY MEASURES		RESTORATION TIME
H. Manual RST LTC operation with calculated post trip voltage below minimum required post trip voltage for existing tap position.	H.1	Declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately
I. Manual TST LTC operation (with RST LTC in automatic) with Delta-V (%) above 1.2%.	I.1	Evaluate OPERABILITY of the offsite circuit associated with the TAT per TS 3.8.1.	Immediately
J. Manual TST LTC operation (with RST LTC in manual) with calculated post trip voltage below minimum required post trip voltage for existing tap position.	J.1	Declare the offsite circuit associated with the TAT inoperable per TS 3.8.1.	Immediately
K. Manual RST LTC operation with calculated post trip voltage monitoring capability unavailable.	K.1	Evaluate OPERABILITY of the offsite circuit associated with the RAT per TS 3.8.1.	Immediately
L. Manual TST LTC operation with calculated post trip voltage monitoring capability unavailable.	L.1	Evaluate OPERABILITY of the offsite circuit associated with the TAT per TS 3.8.1.	Immediately
M. RST unavailable.	M.1	Declare the offsite circuit associated with the RAT inoperable per TS 3.8.1.	Immediately
N. TST unavailable.	N.1	Declare the offsite circuit associated with the TAT inoperable per TS 3.8.1.	Immediately

TECHNICAL VERIFICATION REQUIREMENTS

	VERIFICATION	FREQUENCY
TVR 8.8.4.1	Verify status light 'FWP TRIP ON FAST BUS XFER' located on mechanical vertical panel 'A' is ON when both FWPs are operating.	7 days
TVR 8.8.4.2	Verify generator lockout auxiliary relays associated with main FWP trip on fast bus transfer are FUNCTIONAL.	36 months
TVR 8.8.4.3	Perform a FUNCTIONAL test of the RST LTC and TST LTC to verify stepping capability (only required if no stepping occurred in prior period).	7 days
TVR 8.8.4.4	Perform a FUNCTIONAL test of the RST LTC and TST LTC in manual to verify stepping capability (only required if no manual stepping occurred within the period).	3 months
TVR 8.8.4.5	Perform a FUNCTIONAL test of the RST LTC and TST LTC in automatic to verify stepping capability and automatic response of the LTC voltage regulators (only required if no automatic high speed return stepping occurred within the period).	3 months
TVR 8.8.4.6	Perform a diagnostic maintenance calibration and test to verify settings and functionally check the LTC voltage regulators of the RST LTC and TST LTC.	18 months
TVR 8.8.4.7	Perform the recommended maintenance-free interval complementing checks of the RST and TST on-line tap changers (OLTCs) and the LTC control cabinets.	18 months
TVR 8.8.4.8	Perform a maintenance test to check the internals of the RST and TST OLTCs.	36 months

BACKGROUND

When a fast bus transfer occurs as a result of energizing relays 86/T1A and 86/T1B (instantaneous generator lockout) or 86/T1C and 86/T1D (time delay turbine trip), a large amount of electrical load is rapidly applied to the reserve auxiliary transformer (RAT). Upgrades to the RAT / reserve supply transformer (RST) system increase the system voltage drop and make it more difficult for the RAT / RST to support the added load during a fast bus transfer.

The RST and tertiary supply transformer (TST) are each equipped with an on-line tap changer (OLTC). The load tap changer (LTC) allows plant operators the capability of correcting bus / line voltage. The maximum and minimum range of the LTC is +/- 10% of the secondary voltage of the RST or TST and includes 33 taps (nominal, 16 taps to lower voltage and 16 taps to raise voltage) to adjust the voltage. The LTC can operate in either automatic or manual modes.

American Transmission Company (ATC) and Midwest Independent System Operator (MISO) have the ability to monitor Delta-V (%), used with automatic LTC operation, and post trip voltage, used with manual LTC operation. ATC has the capability to monitor if either LTC is in automatic or manual operating mode and to monitor both LTC tap positions.

Operation of a transformer LTC in automatic is predicated on having the ability to monitor Delta-V (%) (138kV bus voltage % change) for any auto LTC tap position. This voltage change (%) is the predicted voltage change, after any post trip voltage drop, with any transmission system configuration.

Operation of a transformer LTC in manual is predicated on having the ability to monitor post trip voltage (138kV bus voltage) for the fixed tap position of the LTC. This voltage is the predicted voltage, after any post trip voltage drop, with any transmission system configuration.

TNC and APPLICABILITY

The RAT / RST shall be FUNCTIONAL.

With both feedwater pumps (FWPs) operating, when the RST LTC is operated in manual, control room operators are required to select a single FWP ('A' or 'B') to trip in the event a fast bus transfer occurs.

With both FWPs operating, when the RST LTC is operated in automatic and Delta-V (%) is above 0.45% (Reference 2), control room operators are required to select a single FWP ('A' or 'B') to trip in the event a fast bus transfer occurs.

Tripping a selected FWP during initiation of a fast bus transfer of non-safety related buses to the RAT ensures that during a loss of power from the main auxiliary transformer (MAT) adequate voltage will remain at the RAT during a transfer.

TNC and APPLICABILITY (continued)

For automatic RST LTC operation, ATC has established a Delta-V (%) alarm of 1.2% to alert Kewaunee Power Station (KPS) of an abnormal distribution system condition associated with the RAT / RST that could lead to an extended degraded voltage condition on the connected safeguard bus, if KPS was to experience a unit trip. Above a Delta-V of 1.2%, concurrent with unit trip, a degraded voltage actuation could exist that would disconnect the safeguard bus from the preferred offsite circuit and start and load the emergency diesel generator to repower the safeguard bus.

For manual RST LTC operation, ATC has established post trip voltage alarms for each RST LTC tap position, to alert KPS of an abnormal distribution system condition associated with the RAT / RST that could lead to an extended degraded voltage condition on the connected safeguard bus, if KPS was to experience a unit trip. With an analyzed post trip voltage below the required post trip voltage for the selected tap position, concurrent with unit trip, a degraded voltage actuation could exist that would disconnect the safeguard bus from the preferred offsite circuit and start and load the emergency diesel generator to repower the safeguard bus.

The tertiary auxiliary transformer (TAT) / TST shall be FUNCTIONAL.

For automatic TST LTC operation, KPS has established a Delta-V (%) requirement of 5.0% to take action to prevent an abnormal distribution system condition associated with the TAT / TST that could lead to an extended degraded voltage condition on the connected safeguard bus, if KPS was to experience a unit trip. Above a Delta-V of 5.0%, concurrent with unit trip, a degraded voltage actuation could exist that would disconnect the safeguard bus from the preferred offsite circuit and start and load the emergency diesel generator to repower the safeguard bus.

For manual TST LTC operation, KPS has established a requirement to maintain the TST LTC tap position at or above five (5) taps below the RST LTC tap position. This will ensure that the ATC alarm set for automatic RST LTC operation associated with Delta-V, and the ATC alarms set for manual RST LTC tap positions based on minimum required post trip voltages will be conservative for the manual TST LTC tap positions. With the alarm associated with Delta-V, and the alarms associated with the RST LTC tap positions (concurrent with the analysis between the minimum required post trip voltages for the TST LTC and RST LTC tap positions), ATC would be able to alert KPS of an abnormal distribution system condition associated with the TAT / TST that could lead to an extended degraded voltage condition on the connected safeguard bus, if KPS was to experience a unit trip. With an analyzed post trip voltage below the required post trip voltage for the

TNC and APPLICABILITY (continued)

selected tap position, concurrent with unit trip, a degraded voltage actuation could exist that would disconnect the safeguard bus from the preferred offsite circuit and start and load the emergency diesel generator to repower the safeguard bus.

CONTINGENCY MEASURES

A.1

With both FWPs operating, if the main FWP trip on fast bus transfer circuit is unavailable while the RST LTC is in manual, the ability to obtain a fast bus transfer from the MAT to the RAT without actuating safeguard degraded voltage relaying would not be guaranteed. The KPS GDC 39 (meeting the intent of GDC 17) described in the Updated Safety Analysis Report (USAR) (Reference 3) may not be met. Because the offsite power source could potentially not be relied upon under this condition, CONTINGENCY MEASURE A.1 requires immediate action.

A.2

With both FWPs operating, if the main FWP trip on fast bus transfer circuit is unavailable while the RST LTC is in automatic with Delta-V greater than 0.45%, the ability to obtain a fast bus transfer from the MAT to the RAT without actuating safeguard degraded voltage relaying would not be guaranteed. The KPS GDC 39 (meeting the intent of GDC 17) described in the USAR (Reference 3) may not be met. Because the offsite power source could potentially not be relied upon under this condition, CONTINGENCY MEASURE A.2 requires immediate action.

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

If the Delta-V monitoring capability is unavailable from both ATC and MISO, automatic RST LTC and TST LTC operation would be considered Non-FUNCTIONAL and CONTINGENCY MEASURES B.1 and C.1 would be required. Because the offsite power source could potentially not be relied upon under this condition, CONTINGENCY MEASURES B.2 and C.2 require immediate action.

CONTINGENCY MEASURES (continued)

D.1

If the Delta-V (%) is greater 1.2% while Buses 1-3 and 1-4 are aligned to the MAT, Automatic RST LTC operation may not meet the analytical requirements to maintain the RAT / RST offsite circuit operable and CONTINGENCY MEASURE D.1 would be immediately required.

E.1

If the Delta-V (%) is greater 2.7% while Bus 1-3 or Bus 1-4 is aligned to the RAT, automatic RST LTC operation may not meet the analytical requirements to maintain the RAT / RST offsite circuit operable and CONTINGENCY MEASURE E.1 would be immediately required.

F.1

If the Delta-V (%) is greater 4.5% while Buses 1-3 and 1-4 are aligned to the RAT, automatic RST LTC operation may not meet the analytical requirements to maintain the RAT / RST offsite circuit operable and CONTINGENCY MEASURE F.1 would be immediately required.

G.1

If the Delta-V (%) is greater 5.0%, automatic TST LTC operation may not meet the analytical requirements to maintain the TAT / TST offsite circuit operable and CONTINGENCY MEASURE G.1 would be immediately required.

H.1

If the calculated post trip voltage is below the minimum required post trip voltage for the operating tap position, manual RST LTC operation may not meet the analytical requirements to maintain the RAT / RST offsite circuit operable and CONTINGENCY MEASURE H.1 would be immediately required.

CONTINGENCY MEASURES (continued)

I.1

If the Delta-V (%) is greater than 1.2% (conservative to the analysis specified in Reference 7), manual TST LTC operation (with the RST LTC in automatic) may not meet the analytical requirements to maintain the TAT / TST offsite circuit operable and CONTINGENCY MEASURE I.1 would be immediately required.

J.1

If the calculated post trip voltage is below the minimum required post trip voltage for the operating tap position, manual TST LTC operation (with the RST LTC in manual) may not meet the analytical requirements to maintain the TAT / TST offsite circuit operable and CONTINGENCY MEASURE J.1 would be immediately required.

K.1, and L.1

If the calculated post trip voltage monitoring capability is unavailable from both ATC and MISO, manual RST LTC or TST LTC operation may not meet the analytical requirements to maintain the RAT / RST or TAT/ TST offsite circuits operable and CONTINGENCY MEASURES K.1 and L.1 would be immediately required.

M.1, and N.1

If the RST or TST is unavailable, the RAT / RST or TAT / TST offsite circuit would be considered inoperable and CONTINGENCY MEASURE M.1 or N.1 would be immediately required.

TECHNICAL VERIFICATION REQUIREMENTS

All TECHNICAL VERIFICATION REQUIREMENTS tests, calibrations and checks associated with the LTCs are per the correspondence found in References 4 and 5.

TVR 8.8.4.1

The status light 'FWP TRIP ON FAST BUS XFER' should be illuminated when the FWP trip on fast bus transfer selector switch is selected to trip FWP 'A' or 'B'.

TVR 8.8.4.2

Generator lockout relays and generator auxiliary relays are functionally tested every 36 months in accordance with the plant's maintenance testing procedure for FUNCTIONAL tripping of generator zone lockout relay outputs.

TVR 8.8.4.3

A FUNCTIONAL test should be performed weekly in manual to verify lower and raise stepping capability of the LTC (only required if no stepping occurred in prior week). Auto stepping of the LTC within the prior week also satisfies this requirement.

TVR 8.8.4.4

A FUNCTIONAL test should be performed quarterly in manual to verify stepping capability of the LTC. Manual stepping of the LTC within the prior quarter also satisfies this requirement.

TVR 8.8.4.5

A FUNCTIONAL test should be performed quarterly in automatic to verify stepping capability of the LTC and automatic response of the LTC voltage regulators. Auto stepping of the LTC, along with high speed return stepping, within the prior quarter also satisfies this requirement.

TVR 8.8.4.6

A diagnostic maintenance calibration and test should be performed every refueling outage to verify settings and functionally check the LTC voltage regulators. This includes verification of the OLTC motor drive operation for both normal expected operation (voltage in and outside the normal control bandwidth) and abnormal operation (voltage outside the voltage limit band).

TECHNICAL VERIFICATION REQUIREMENTS (continued)

TVR 8.8.4.7

The vendor recommended maintenance-free interval complementing checks of oil sampling, vacuum interrupter system test, motor drive condition checks, dehydrating breather checks, and checks for oil leaks should be performed every refueling outage. Additionally, LTC cabinets are to be visually inspected to check for loose connections, damage, overheating, deterioration, and relay degradation.

TVR 8.8.4.8

A maintenance test should be performed every other refueling outage to check the internals of the OLTC cabinet, including vacuum interrupter, associated motor drive circuitry and equipment, and monitoring system. The maintenance test should be performed per the vendor manual for LTC Type RMV-II, which includes a vacuum interrupter examination for mechanical test, contact erosion indicator check, and Hi-Pot (if required); bypass switch check; and preparation of the LTC for service checks. Additionally, perform checks for loose connections, damage and contact wear.

REFERENCES

1. TS 3.8.1
2. Calculation C11450 Rev. 2, Addendum D, Attachments 3 & 5
3. USAR Section 8.1.1.2
4. License Amendment Request 236, and Supplement dated 1/18/11 (KW-CORR-LAR-NRC-11-003)
5. License Amendment No. 209 dated 7/29/11 (KW-CORR-SER-K-11-101)
6. Calculation C11450 Rev. 2, Attachment 51
7. Calculation C11450 Rev. 2, Addendum I

ATTACHMENT 3

TECHNICAL SPECIFICATIONS BASES CHANGES AND TECHNICAL REQUIREMENTS MANUAL CHANGES

KEWAUNEE POWER STATION TECHNICAL REQUIREMENTS MANUAL

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KEWAUNEE POWER STATION
DOMINION ENERGY KEWAUNEE, INC.

KEWAUNEE POWER STATION TECHNICAL REQUIREMENTS MANUAL
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8.3.7-1	1	February 16, 2012
8.3.7-2	1	February 16, 2012
8.3.7-3	1	February 16, 2012
8.3.7-4	1	February 16, 2012
8.3.7-5	1	February 16, 2012
8.3.8-1	0	February 12, 2011
8.3.8-2	0	February 12, 2011
8.3.8-3	0	February 12, 2011
8.3.8-4	0	February 12, 2011
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8.3.9-7	1	July 9, 2012
8.3.9-8	1	July 9, 2012
8.4.1-1	0	February 12, 2011
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8.4.1-3	0	February 12, 2011
8.4.1-4	0	February 12, 2011
8.4.1-5	0	February 12, 2011
8.4.1-6	0	February 12, 2011
8.4.2-1	0	February 12, 2011
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8.4.3-1	0	February 12, 2011
8.4.3-2	0	February 12, 2011
8.4.3-3	0	February 12, 2011
8.4.3-4	0	February 12, 2011
8.5.1-1	1	July 18, 2011
8.5.1-2	1	July 18, 2011
8.5.1-3	1	July 18, 2011
8.5.2-1	1	January 11, 2013
8.5.2-2	1	January 11, 2013
8.5.2-3	1	January 11, 2013
8.5.2-4	1	January 11, 2013
8.5.2-5	1	January 11, 2013
8.5.2-6	1	January 11, 2013
8.6.1-1	0	February 12, 2011
8.6.1-2	0	February 12, 2011
8.6.1-3	0	February 12, 2011
8.7.1-1	0	February 12, 2011
8.7.1-2	0	February 12, 2011
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8.7.2-4	1	May 19, 2011
8.7.2-5	1	May 19, 2011
8.7.3-1	0	February 12, 2011
8.7.3.2	0	February 12, 2011
8.7.3-3	0	February 12, 2011
8.7.3-4	0	February 12, 2011
8.7.3-5	0	February 12, 2011
8.7.3-6	0	February 12, 2011
8.7.4-1	0	February 12, 2011
8.7.4-2	0	February 12, 2011
8.7.4-3	0	February 12, 2011
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8.8.1-8	1	June 15, 2012
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8.8.3-5	1	April 25, 2012
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8.8.3-9	1	April 25, 2012
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8.8.4-1	0	January 29, 2013
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