WOLF CREEK
NUCLEAR OPERATING CORPORATION

Stephen E. Hedges
Vice President Operations and Plant Manager

March 6, 2006

WO 06-0014

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

References:

1) Letter WO 03-0057, dated October 30, 2003, from B. T. McKinney, WCNOC, to the NRC

2) Letter ET 05-0017, dated August 31, 2005, from T. J. Garrett, WCNOC, to the NRC

3) Letter ET 05-0025, dated November 18, 2005, from T. J. Garrett, WCNOC, to the NRC

Subject: Docket No. 50-482: Supplement to Revision to Technical Specifications – Extensions of AC Electrical Power Distribution Completion Times

Gentlemen:

Reference 1 provided Wolf Creek Nuclear Operating Corporation's (WCNOC) application to revise Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Times for the Required Actions associated with an inoperable diesel generator (DG). The amendment application also proposed revising TS 3.8.9, "Distribution Systems – Operating," to extend the Completion Time for one AC vital bus subsystem inoperable. Reference 2 provided responses to a request for additional information and information per Appendix E of NRC letter dated July 1, 2005, "Draft Safety Evaluation for Topical Report WCAP-15622, "Risk-Informed Evaluation of Extensions to AC Electrical Power System Completion Times" (TAC NO. MB2257)." Reference 3 proposed additional changes to TS 3.8.1 and the associated TS Bases to provide additional requirements associated with the Sharpe Station.

Teleconferences were held between NRC personnel and WCNOC personnel on December 14, 2005, December 20, 2005, December 21, 2005, January 19, 2006, and February 22, 2006. As a result of the teleconferences and additional questions provided by electronic mail, WCNOC is providing an additional change to the Completion Time for the proposed Required Action B.4.2.1 provided in Reference 3 as well as responses to additional NRC questions. WCNOC is withdrawing the proposed changes to TS 3.8.9 based on the potential additional time and information to resolve concerns associated with extending the Completion Time for one AC vital bus subsystem inoperable.

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WCNOC requests the NRC to issue an amendment based on the above references with specific license conditions for addressing testing of the Sharpe Station and inclusion of the risk impact of the Sharpe Station in the Safety Monitor™. Reference 2 had requested NRC approval of this license amendment request by December 23, 2005 to support performing on-line DG maintenance activities in the first quarter 2006 in support of Refueling Outage 15, scheduled for October 2006. WCNOC is requesting NRC approval of the amendment request by March 22, 2006. This amendment will be implemented within 90 days, contingent on the date of NRC approval.

Attachment I provides responses to questions transmitted to WCNOC by electronic mail on December 12, 2005. Attachment II provides the additional changes to proposed Required Action B.4.2.1. Attachment III provides for information only the associated changes to the TS Bases for the change to proposed Required Action B.4.2.1 and incorporates the requirement for a load capability test/verification within 8 months prior to utilization of the 7-day Completion Time into the discussion on administrative controls applied during use of Required Action B.4.2.2. Attachment IV provides proposed conditions to the operating license. Attachment V provides the regulatory commitments associated to the issuance of an amendment and these commitments supersede commitments provided in References 1 through 3.

The additional changes to the Technical Specifications and the proposed changes to the Operating License in this submittal have been reviewed by the Plant Safety Review Committee. The additional information provided in the Attachments does not impact the conclusions of the No Significant Hazards Consideration provided in Reference 1. In accordance with 10 CFR 50.91, a copy of this submittal is being provided to the designated Kansas State official.

If you have any questions concerning this matter, please contact me at (620) 364-4190, or Mr. Kevin Moles at (620) 364-4126.

Very truly yours,

Stephen E. Hedges

SEH/rlt

Attachments: I - Responses to Request for Additional Information
II - Markup of Technical Specification Pages
III - Proposed TS Bases Changes for Information Only
IV - Proposed Operating License Conditions
V - List of Commitments

cc: T. A. Conley (KDHE), w/a
J. N. Donohew (NRC), w/a
W. B. Jones (NRC), w/a
B. S. Mallett (NRC), w/a
Senior Resident Inspector (NRC), w/a

STATE OF KANSAS)
) SS
COUNTY OF COFFEY)

Stephen E. Hedges, of lawful age, being first duly sworn upon oath says that he is Vice President Operations and Plant Manager of Wolf Creek Nuclear Operating Corporation; that he has read the foregoing document and knows the contents thereof; that he has executed the same for and on behalf of said Corporation with full power and authority to do so; and that the facts therein stated are true and correct to the best of his knowledge, information and belief.

By________________________
Stephen E. Hedges
Vice President Operations and Plant Manager

SUBSCRIBED and sworn to before me this 6 day of March, 2006.

RHONDA L. TIEMEYER
MY COMMISSION EXPIRES
January 11, 2010
OFFICIAL SEAL

Rhonda L. Tiemeyer
Notary Public

Expiration Date January 11, 2010

RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION

This Attachment provides Wolf Creek Nuclear Operating Corporation's (WCNOC's) responses to questions associated with WCNOC's request to extend the Completion Times for the Required Actions associated with an inoperable diesel generator (DG). An initial set of electrical related questions were provided by electronic mail on December 8, 2005 with additional similar questions provided on December 12, 2005. Responses were provided electronically to these questions on December 9, 2005, December 14, 2005, and updated responses provided on December 20, 2005 as a result of the December 14, 2005 teleconference. On February 1, 2006, additional electrical-related questions were received by electronic mail. Responses to these questions were provided by electronic mail on February 8, 2006. Due to several of the electrical-related questions being duplicative, responses have only been provided to a subset of questions. On December 12, 2005 two sets of Probabilistic Safety Assessment (PSA) related questions were provided by electronic mail. Responses to the PSA related questions were provided by electronic mail on December 20, 2005.

ELECTRICAL QUESTIONS (from December 8 and December 12, 2005)

1. Discuss the capability of the Sharpe stations capability to start emergency loads when called upon as a replacement source. Are the Caterpillar units capable of maintaining adequate voltage during the emergency loading cycle to prevent contactor or solenoid drop outs due to undervoltage? Are these units relying on external fuel supply or provided with sufficient onsite storage for long term operation? Are the starting mechanisms or cooling systems susceptible to failures from external events?

Response: A steady state voltage drop analysis, coupled with a start of the largest motor load, has been performed with four Sharpe Station generator sets (gensets) connected to one safety bus. The analysis demonstrates that voltages are adequate to maintain safety related equipment running and adequate voltage is available to the motor control centers to prevent contactor or relay drop out. During the teleconference on December 14, 2005, the NRC reviewer questioned the adequacy of only performing an analysis in lieu of performing load capacity testing. In letter WO 03-0057 (Attachment II, page 6, RAI 5), WCNOC indicated that the Sharpe Station would be maintained consistent with the manufacturer's recommendations and prudent utility maintenance practices and that maintenance runs are performed on each genset on a monthly basis. Since the Sharpe Station was added for commercial reasons by Kansas Electric Power Cooperative, Inc. (one of 3 owners of the Wolf Creek Generating Station), the gensets are utilized (loaded) on an as needed basis. To qualify/credit the Sharpe Station gensets as peaking units, maximum capability tests were run with all 10 units running in parallel. These capability tests were run during the hottest day of the summer and the substation output power was measured at 19.3 megawatts. These capability tests are run approximately every three years. All 10 units were run for load for six (6) hours, in mid-December 2005, confirming the substation's 20 megawatt output capacity.

WCNOC will perform a one-time load acceptance test of the Sharpe Station. The one-time load acceptance test will be performed prior to the first use of the 7-day Completion Time for pre-planned maintenance activities. The test will demonstrate the capability of the Sharpe Station to successfully start a large motor (1500 hp motor at a nearby gas pumping station) to simulate nuclear plant loads. Based on discussions with the NRC, WCNOC agrees to the conditioning of the operating license for the performance of this test. Attachment IV provides the recommended wording for this license condition.

Additionally, a dynamic voltage flow analysis is being performed, using vendor provided test data for starting large motor loads, to further demonstrate from an analysis perspective that the Sharpe Station would be capable of starting and carrying designated loads, including maintaining adequate voltage and frequency such that performance of powered equipment would be acceptable. This statement means that the analysis will demonstrate that the Sharpe Station genset are capable of starting and carrying designated loads and that the voltage and frequency would be adequate to ensure no damage to equipment and that degraded voltage and loss of voltage functions are not challenged. This analysis may demonstrate that additional gensets are required to supply safety related loads.

Eight of the ten gensets have an underbelly fuel storage tank suitable of fueling the genset for a minimum of 27 hours of operation. The remaining two units have fuel capacity for a minimum of 12 hours. Additional fuel is available from a vendor that can be trucked in on an as needed basis. Additional fuel would be brought to the Sharpe Station in a 4700 gal. capacity tanker. Discussions between the fuel oil vendor and the Kansas Electric Power Cooperative, Inc. (KEPCo) indicated that the fuel oil could be delivered in approximately 2.5 hours. Sharpe Station has no other on-site diesel fuel storage. WCNOC will coordinate with KEPCo, to ensure a fuel oil vendor is available to provide fuel oil to the Sharpe Station on an as needed basis.

Each genset along with its respective starting mechanism and cooling unit are fully enclosed. Each unit is fully separated from other gensets and power transformers.

2. Explain why the proposed 24-hour verification of the Sharpe Station during diesel generator (DG) outages is sufficient during the high risk period rather than an 8-hour verification of gensets availability.

Response: In the original application (letter WO 03-0057), WCNOC had identified that administrative controls would be in place during the voluntary planned maintenance activities to ensure or require that the Sharpe Station be available to provide greater than 8 MW power to a dead bus. The original intent was that a one time verification would be performed prior to entry into the planned maintenance activity to verify that the required Sharpe Station gensets were available with no follow-up verification of availability. Subsequently, based on discussions with the NRC Project Manager on October 31, 2005 and November 2, 2005, WCNOC agreed to provide additional changes to TS 3.8.1 and associated TS Bases that included placing a requirement in the TSs for verifying the required Sharpe Station gensets are available. The Completion Time of "Once per 24 hours" was proposed based on existing TS requirements (Required Actions B.3.1 and B.3.2) that require with one DG inoperable, a determination is made that the OPERABLE DG is not inoperable due to common cause failure OR the performance of SR 3.8.1.2 (DG start). Since the Sharpe Station would typically only be utilized for supplying power to the Class 1E ESF bus in the event of a complete loss of onsite and offsite power, a Completion Time of 24 hours was believed to be a reasonable time period to verify the availability of the required gensets.

In the December 14, 2005 teleconference, the NRC reviewer questioned the acceptability of the a 24 hour Completion Time for verifying the availability of the Sharpe Station based on the information that the available fuel oil for eight of the ten gensets provided 27 hours of operation. WCNOC had identified that the verification of availability would be performed by contacting the KEPCo Operations Center to verify availability based on their remote monitoring capabilities of fuel oil levels in the gensets. WCNOC is proposing to change the proposed TS Required Action Completion Time for verifying the Sharpe Station availability to every 12 hours and utilize on-shift WCNOC personnel to locally verify various parameters to ensure the gensets are available.

3. Will the Sharpe Station be continuously manned for starting, line up, and operation of the units when the units are potentially needed? What type of training will be offered for interactions with the Wolf Creek Generating Station control room? How frequently will the training be conducted? Has the time required for verifying the gensets availability been verified to be within the stated 1.5 hour period?

Response: Sharpe Station is an un-manned peaking unit, fully monitored remotely by KEPCo SCADA equipment. Each genset and breaker status (for availability) is monitored and alarmed back to the KEPCO Operations Center (remote location). Examples of genset alarms include: general trips, general alarms, unit status (run or stop), unit breaker status, unit control (local or remote), fuel readings, and coolant temperatures.

WCNOC had previously indicated during a teleconference with the NRC Project Manager that it was estimated that the Sharpe Station gensets could be locally started (i.e., a system blackout condition exists) and providing power to the Class 1E ESF bus in approximately 1.5 hours. KEPCo personnel have performed with WCNOC plant operations personnel and procedure writers a local start of one genset and determined that the Sharpe Station gensets could be locally started and aligned within 1.5 hours. Based on this evolution WCNOC has developed a procedure in conjunction with KEPCo personnel for aligning the Sharpe Station with the WCGS switchyard. WCNOC has provided training to the operating crews on this procedure. Training is scheduled for the standard two-year rotation.

Prior to performing the preplanned maintenance activity on a DG, a pre-job brief is performed in accordance with procedure AP 22-001, "Conduct of Pre-Job and Post-Job Briefs." This procedure requires that a thorough pre-job brief including a management brief be performed for infrequently performed high-risk tasks and that additional pre-job briefs are to be held on activities that continue into the next shift. It is an Operations practice for high-risk infrequently performed evolutions and tasks to perform a walkdown of the procedure prior to the performance of the activity. Additionally, procedure AI 15C-006, "Conduct of Infrequently Performed Tests or Evolutions," provides guidance for various levels of management to conduct briefings for and provide oversight of infrequently performed tests or evolutions.

4. Explain why the following compensatory measures are not applicable during the extended EDG outage.

- Verify that the offsite power system is stable. This action will establish that the offsite power system is within single-contingency limits and will remain stable upon the loss of any single component supporting the system. If a grid stability problem exists, the planned DG outage will not be scheduled.

- Verify no unnecessary maintenance, installation, or modification work activities are scheduled in the offsite power switchyard or offsite circuits supplying the switchyard during DG outage.

- Verify that no adverse weather conditions expected during the outage period. The DG planned outage will be postponed if any inclement weather is anticipated

- Do not remove the reactor trip breakers from service concurrently during planned DG outage maintenance.

- Do not take the turbine-driven auxiliary feedwater pump out of service concurrently with a DG outage.

- Do not take the AFW level control valves to the steam generators out of service concurrently with any DG outage.

- Do not take the opposite train residual heat removal (RHR) pump out of service concurrently with a DG outage.

Response: Letter WO 03-0057, Attachment I page 19 (Section 4.1.1.2) discusses the Tier 2 compensatory measures and configuration risk management controls associated with an extended DG Completion Time. This information is incorporated into the proposed TS Bases for Required Actions B.4.1, B.4.2.1, and B.4.2.2. See letter ET 05-0025 Attachment IV page 8 for the latest proposed TS Bases.

Letter WO 03-0057 identified that the risk evaluation considers the three-tiered approach as presented in Regulatory Guide 1.177. The objective of the second tier, which is applicable to Completion Time extensions, is to provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when equipment is out of service. If risk-significant configurations do occur, then compensatory measures can be made that avoid, limit, or lessen the importance of these configurations. Section 4.1.1.2 of letter WO 03-0057 is provided below:

4.1.1.2 Tier 2: Avoidance of Risk-Significant Plant Conditions

Additional compensatory measures and configuration risk management controls that will apply when entering the proposed planned, extended DG Completion Time (greater than 72 hours and up to 7 days) include:

- Perform work during a favorable weather period (Sept. 6 through April 22)
- Weather forecast checked for severe weather conditions
- Elective testing and maintenance activities are precluded in the WCGS switchyard that could cause a line outage or challenge offsite power availability
- Additional AC power Sharpe Station available and performance acceptable
- Concurrent work on other key SSCs is not planned (Essential Service Water System, Component Cooling Water System, Motor/Turbine Driven Auxiliary Feedwater Pumps, Residual Heat Removal System)

While in the proposed extended DG Completion Time, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.

There is reasonable assurance that risk-significant plant equipment configurations will not occur when a DG is removed from service to perform on-line maintenance and testing under the proposed TS changes. This assurance is provided by existing TS requirements, but especially by the previously identified restrictions or conditions that will be imposed when the on-line, extended DG Completion Time is utilized.

Therefore, the risk evaluation performed to support the extended DG Completion Time did not identify the reactor trip breakers to be a risk-significant contributor for the plant configuration. However, the Operational Risk Assessment Program (procedure AP 22C-003) would identify any additional equipment that should not be taken out of service in this plant configuration. Letter WO 03-0057, Attachment I page 19 and Attachment II page 26 provide further details regarding this program.

Letter ET 05-0025 (11/18/05) provided additional changes to the TS and TS Bases and provided the revised administrative controls which include the Tier 2 restrictions:

> Administrative controls applied during use of Required Action B.4.2.2 for voluntary planned maintenance activities ensure or require that:
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> a. Weather conditions are conducive to an extended DG Completion Time. The extended DG Completion Time applies during the period of September 6 through April 22.
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> b. The offsite power supply and switchyard condition are conducive to an extended DG Completion Time, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed that would challenge offsite power availability.
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> c. Prior to relying on the required Sharpe Station gensets, the gensets are started and proper operation verified (i.e., the gensets reach rated speed and voltage). The Sharpe Station is not required to be operating the duration of the allowed outage time of the DG, however, it shall be capable of providing greater than 8 MW power to a dead bus (station blackout conditions) to power 1 ESF train.
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> d. No equipment or systems assumed to be available for supporting the extended DG Completion Time are removed from service. The equipment or systems assumed to be available (including required support systems, i.e., associated room coolers, etc.) are as follows:
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> - Auxiliary Feedwater System (three trains)
> - Component Cooling Water System (both trains and all four pumps)
> - Essential Service Water System (both trains)
> - Emergency Core Cooling System (two trains).

Attachment III provides additional TS Bases changes and incorporates the requirement for a load capability test/verification within 8 months prior to utilization of the 7-day Completion Time into the discussion on administrative controls applied during use of Required Action B.4.2.2. Procedure SYS KJ-200, "Inoperable Emergency Diesel," will include the administrative controls associated with the utilization of the 7-day Completion Time of Required Action B.4.2.2 in TS 3.8.1.

During the teleconference on December 15, 2005, the NRC reviewer requested information concerning the interface with the transmission system operator. WCNOC procedure AP 21C-001, "Substation Protection," establishes responsibilities and defines necessary interfaces, communications, and coordination with Westar Energy to ensure control of maintenance which could affect the substation and availability of offsite power. As described in AP 21C-001 Attachment B; Westar Energy Transmission Services (System Operations) is required to run the predictive model once every hour using a Contingency Analysis Program. The program will capture actual grid configuration, power flows and generation to predict a Wolf Creek 345kV switchyard voltage in the event of a WCGS unit trip. The program provides alarms to the Control Operator signifying a predicted degraded voltage condition if WCGS were to go off-line. If the predicted condition cannot be corrected, then the System Operator will notify the WCGS Control Room and provide an estimated time to correct the condition. When the WCGS Control Room notifies System Operations of the plan to remove a DG from service, a discussion concerning the previous grid stability, current grid stability, and scheduled work/other plant outages that may affect the grid stability are conducted.

ELECTRICAL QUESTIONS (from February 2, 2006)

1. Explain the bases that starting the 1500 hp motor at the Sharpe Station reflects worst case loading for a safety bus at the plant.

Response: The start of the 1500 HP motor (located at a nearby gas pumping station) is not considered to be worst case or bounding for the 1750 HP safety motor start but it is considered to be a challenging functional test that will confirm that the Sharpe Station gensets have the capability to withstand and recover voltage and frequency during the motor start. A bounding configuration for this test can be controlled by the use of the number of gensets used for the test start of the 1500 HP motor. However, due to commercial issues of damaging the 1500 HP motor, enough generation will be connected during the test to insure that the motor has adequate voltage and has a successful start. To validate the ability to predict a successful start of the 1500 HP motor, an ETAP model will be developed to simulate the test configuration. The test results will be used to validate the model's ability to predict the voltage and frequency at the 1500 HP motor terminals and at the gensets common bus. A summary of the expected loads for the WCGS electrical safety bus (Class 1E ESF bus) are discussed below.

WCGS plant (manual) loading for one electrical safety bus for cold shutdown conditions with a station blackout is as follows: Connected 480 V Motor loads (1235 KW), one Essential Service Water (ESW) pump (1750 HP), one Centrifugal Charging Pump (600 HP), one Component Cooling Water Pump (700 HP), one Residual Heat Removal Pump (500 HP), and one Auxiliary Feed Water Pump (800 HP) and non-safety loads (455 KW).

The largest safety load is the ESW pump (1750 HP). To simulate the start of the largest motor load, ESW (1750 HP) test parameters will be scaled to coincide with a safe and successful start of an existing 1500 HP pump presently connected to the 69 kV system. The test configuration will have the appropriate number of gensets operating in parallel and in an islanded (isochronous) mode. Resistive and reactive load banks will be used to simulate connected base loads prior to starting the large motor load. This test set up simulates starting a 1750 HP load with connected 480 V motor loads as expected plant loads would be started. To insure a successful test without damaging equipment a dynamic model of the test configuration will also be developed to predict voltage and frequency values at the motor terminals and at the gensets common bus. The test results will be used to validate a dynamic voltage drop model.

2. Discuss the predicted performance of the gensets that would demonstrate the gensets have the capability of providing sufficient ac power to a safety bus at the plant.

Response: Wolf Creek along with the Sharpe Station owners (KEPCo) will conduct a joint test to demonstrate that the gensets have the capability to carry initial loads and successfully start a large motor load and reject the same large motor without overspeed of the gensets. The test configuration will simulate WCGS plant loading conditions through the use of the 69 kV line and step down transformers to a large 1500 HP motor. The test will also demonstrate the gensets capability to recover voltage and frequency after the initial inrush during starting so as not to challenge plant safety bus first and second level voltage protection (i.e., loss of voltage and degraded voltage relays). The test and modeling will demonstrate that adequate voltage is maintained to all electrical equipment and identify any limiting conditions to consider in alignment of electrical power to a safety bus from the gensets.

3. Discuss the validation of the software for adequacy of voltage assessments at full loading.

Response: It is Wolf Creek's intent to validate the accuracy of the computer model by using the results of the test that will start a 1500 HP motor at the gas pumping station near the Sharpe Station. The data obtained from the test will be compared to the computer model to validate that the genset models are correct. For the Wolf Creek loads, the motor starts that are modeled will be compared to the motor and pump manufacturer curves to validate that the starting and running characteristics are in agreement with the manufacturer data.

4. Commit to demonstrate adequate capacity before putting the Sharpe Station in service as stated in NUMARC 87-00 Appendix B.10.

Response: NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," Rev. 1, Appendix B.10, states:

> Unless otherwise governed by technical specifications, the AAC power 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. Once every refueling outage, a timed start (within the period specified under blackout conditions) and rated load capacity test shall be performed.

WCNOC letter WO 03-0057, Attachment II, beginning on page 6 of 24 (response to RAI 5), identified that the Sharpe Station is credited as an additional AC power source in the 1998 PSA model modified for the DG Completion Time Extension and is not credited as an Alternate AC (AAC) power source as defined in Regulatory Guide 1.155, "Station Blackout." The information provided further indicates that maintenance runs are performed on each genset on a monthly basis and maintenance is performed consistent with the manufacturer's recommendations and prudent utility practice. On a monthly basis, Martin Tractor performs a walk-around inspection for fuel oil/coolant leaks, checking battery condition, and verifying heaters are on. Following the walk-around, each gensets is started locally and run for 15 minutes and general running conditions are observed. The gensets are then shutdown and restarted remotely from the Sharpe Station switchgear room and run for an additional 15 minutes, where voltage and frequency are verified. As discussed in the response to question 1 on page 1 of this

Attachment, approximately every three years maximum capability tests are run with all 10 gensets running in parallel for qualification/credit as a peaking unit. Since the Sharpe Station is a commercial peaking unit, it is run for load on an as needed basis (e.g., the gensets were run in mid-December, 2005, for 6 days at loaded conditions).

In WCNOC letter ET 05-0025, WCNOC agreed to starting and verifying proper operation (i.e., the Sharpe Station gensets reach rated voltage and speed) prior to relying on the required gensets. The Technical Specifications were also revised to include a periodic verification (once per 24 hours) of the required gensets availability during the duration of the pre-planned maintenance activities. Subsequently, WCNOC indicated that the periodic verification would be performed once per 12 hours (see question 2 in the electrical questions of December 8 and December 12, 2005). Eight of the ten gensets have an underbelly fuel storage tank suitable of fueling the genset for a minimum of 27 hours of operation. The remaining two units have fuel capacity for a minimum of 12 hours. Additional fuel is available from a vendor that can be trucked in on an as needed basis. Additional fuel would be brought to the Sharpe Station in a 4700 gal. capacity tanker. Discussions between the fuel oil vendor and the Kansas Electric Power Cooperative, Inc. (KEPCo) indicated that the fuel oil could be delivered in approximately 2.5 hours. Sharpe Station has no other on-site diesel fuel storage. WCNOC will coordinate with KEPCo, to ensure a fuel oil vendor is available to provide fuel oil to the Sharpe Station on an as needed basis.

In a September 29, 2005, NRC safety evaluation for the Beaver Valley Power Station, the safety evaluation states the following:

> If the licensee chooses a temporary AACPS, its availability would be determined by (1) starting the AACPS and verifying proper operation, (2) verifying that sufficient fuel is available onsite to support 24 hours of operation, and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe shutdown loads. Subsequently, when not in operation, a status check for availability will also be performed once every 72 hours. This check consists of (1) verifying the AACPS is mechanically and electrically ready for operation, (2) verifying that sufficient fuel is available onsite to support 24 hours of operation, and (3) ensuring that the AACPS is in the correct electrical alignment to supply power to designated safe-shutdown loads.
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> If the licensee chooses a permanent AACPS, its availability would be determined to be available by starting the AACPS and verifying a proper operation. In addition, initial and periodic testing, surveillance, and maintenance will conform to NUMARC 87-00, Revision 1, Appendix B, "Alternate AC Power Criteria," guidelines. The guidelines include provisions for quarterly functional testing, timed starts and load capacity testing on a fuel-cycle basis, surveillance and maintenance consistent with manufacturer's recommendations, and initial testing of the capability to power required shutdown equipment within the necessary time.

WCNOC considers the Sharpe Station to be a temporary additional AC power source since the unit is owned and operated by KEPCo. Letter WO 03-0057, page 4 of Attachment I, and letter ET 05-0016, page 4 of Attachment I (response to question 8), provides details on the Operating Agreement between WCNOC and KEPCo. The Operating Agreement specifically states: "Whereas, KEPCo's primary purpose for constructing the Sharpe Station is to supply power to its member distribution cooperatives and a purpose for siting it near Wolf Creek is to provide emergency back-up power for Wolf Creek, specifically, to improve availability and reliability of sufficient AC power for planned or postulated Wolf Creek plant conditions including planned

onsite emergency diesel generator maintenance, emergent failure of one onsite emergency diesel generator, complete loss of all onsite emergency AC power, and grid perturbations or loss of a normal offsite power source to Wolf Creek; and ...." Based on the above information and information previously provided, WCNOC considers that the administrative controls established for the use of the Sharpe Station exceed those controls identified in the Beaver Valley Power Station safety evaluation for a temporary alternate AC power source. Regulatory Guide 1.155, "Station Blackout," Section 2, Offsite Power, indicates that procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. Nearby power source includes such items as nearby or onsite gas turbine generators, portable generators, hydrogenerators, and black-start fossil power plants. The Sharpe Station has local black-start capability. As discussed in the response to Question 3 (from the first set of electrical questions), WCNOC has developed a procedure in conjunction with KEPCo personnel for aligning the Sharpe Station with the WCGS switchyard.

Since the Sharpe Station is not credited for meeting the requirements of 10 CFR 50.63, "Loss of alternating current power," WCNOC believes that we should not be required to commit to the guidance of NUMARC 87-00, Appendix B.10. As discussed in letter WO 03-0057, the results obtained from the risk evaluation demonstrate that the risk of performing DG on-line maintenance under the extended Completion Time is acceptably small. The performance of maintenance and testing consistent with the manufacturer recommendations and the use of the station as a commercial peaking unit provides reasonable assurance that the gensets will operate when required.

On February 22, 2006, a teleconference was conducted at the request of the NRC to further discuss the testing of the Sharpe Station genset. The NRC indicated that approval of the amendment request was contingent on conducting load capability testing/verification prior to each utilization of the proposed 7-day Completion Time of Required Action B.4.2.2 for preplanned maintenance on a WCGS diesel generator. The load capability testing/verification will be verified to have been performed within 8 months prior to utilization of the 7-day Completion Time. The load capability testing/verification will consist of either crediting a running of the gensets for load for commercial reasons for greater than 1 hour or tested by loading of the gensets for greater than 1 hour to a load equal to or greater than required to supply safety related loads in the event of a station blackout. WCNOC will coordinate with KEPCo to ensure the load capability testing/verification is performed within 8 months prior to each utilization of the 7-day Completion Time. Attachment III provides additional TS Bases changes to incorporate this requirement into the discussion on administrative controls applied during use of Required Action B.4.2.2. The NRC has indicated that the load capability testing/verification is to be considered a requirement. As such, WCNOC agrees to the conditioning of the operating license to include this requirement. Attachment IV provides recommended wording for this license condition.

PROBABILISTIC SAFETY ANALYSIS QUESTIONS

1. PRA model data is quite old (1994) for data and 1998 for plant procedures. Are results sensitive to more recent plant data and configuration?

Response: The conclusions of the PRA evaluation to support DG CT would not change with the inclusion of more recent plant data. While individual values would most likely change a small amount, the results would be in line with the current results. It is important to note that a comparison to previous data is not the primary objective. Rather, it is to contrast the two differing plant configurations, for which the same data is used.

2. Licensee states that PRA updates are an ongoing process but PRA is a 1998 revision?

Response: PSA guidance provides recommendations on maintaining the Wolf Creek PRA model. The revision date for PRA updates refers to the cutoff date for the consideration of plant data when updating the model. This means the PRA update began in 1998 and considered new plant data up to that point. The 1998 update was completed and approved the last half of 1999. This is the model of record at the time of submittal for this TS change request.

3. Has the safety monitor been updated to reflect the changes in the PRA to support the DG CT?

Response: No. PSA guidance specifies how plant configuration changes or PRA model features should be controlled to ensure the PRA model accurately represents the as-operated plant for risk assessments. Inclusion of the risk impact of the Sharpe Station in the Safety Monitor™ will be accomplished prior to the first utilization of the extended DG Completion Time. An activity will be added to the Activity Table of the Safety Monitor™ that will account for the impact of the plant configuration associated with crediting the Sharpe Station during use of the subject DG extended Completion Time. As indicated in Section 4.1.1.1.5 of Attachment 1 to letter WO 03-0057, the added activity will adjust the Station Blackout flag event value. The added activity will also reduce the Loss of Offsite Power initiating event frequency as indicated in the response to RAI 8 of Attachment II to letter WO 03-0057.

With inclusion of this activity to Safety Monitor™, the configuration-specific risk (Tier 3) will be properly reflected by taking the appropriate EDG out of service. Addition of this activity will also allow the determination of the risk for other potential combinations of equipment removed from service or emergent plant conditions for the time period of the extended DG Completion Time (Tier 3 evaluation).

4. What model was used to evaluate the DG completion time? The PRA or safety monitor? If the safety monitor was used is it appropriate for both CDF and LERF?

Response: The Wolf Creek PRA model was quantified using the WinNUPRA™ code for this evaluation. The Safety Monitor™ was not used although it does calculate both CDF and LERF values. Safety Monitor™ uses zero test-and-maintenance to approximate actual plant condition risk values in a "real-time" fashion. Using zero test-and-maintenance is not appropriate for this application. (See Question 10 for discussion on test-and-maintenance.)

5. For what scenarios is Sharp station beneficial since it utilizes overhead lines and enters the switchyard? Weather, seismic and plant centered would seem to be limited based on the configuration of Sharp station. How is the risk benefit handled in the PRA? Does the licensee quantify this benefit in its submittal? What were the causes of any LOOP events that occurred at wolf creek?

Response: Letter WO 03-0057, Attachment I, Section 4.1.1.1.5 (page 14) and RAI 8 in letter WO 03-0057, Attachment II (page 11) provided a discussion on scenarios impacted by use of the Sharpe Station capabilities. WCNOC performed a "reduced Scope" seismic analysis for the IPEEE. Plants that fall under "reduced Scope" are in the lowest seismic zone and the probability of a seismic event at the Wolf Creek site is very low. An extended Completion Time for the DGs does not appreciably increase the risk of core damage due to a seismic event. WCGS is also situated such that external flooding does not present an appreciable amount of risk to the plant (USAR Section 2.4.2). Finally, the impact of weather on the plant has been considered and has previously been discussed in Section 4.1.1.2, Section 4.1.1.3, and in RAI 8 (Attachment II) of letter WO 03-0057. The Tier 2 restrictions are proposed to be incorporated into the TS Bases as indicated in Attachment III. The impact of weather will be incorporated with the changes to the Safety Monitor™ as discussed in the response to Question 3 above.

In developing WCNOC's input to item B.1.b of Temporary Instruction (TI) 2515/156, "Offsite Power System Operational Readiness," WCNOC determined that there have been no LOOP events (as defined in the TI) experienced at WCGS. This information was provided in letter ET 05-0016, Attachment II, Item E.1.2 (page 2).

Below is Section 4.1.1.1.5 from letter WO 03-0057:

> 4.1.1.1.5 - <u>Extension of 1998 WCGS PSA Model For DG Completion Time Extension</u>
> The PSA model to support the proposed extension of the DG Completion Time is a partial update that addresses the inclusion of Sharpe Station fault trees, DG T&M values, reactor coolant pump seal LOCA values, and Loss of Offsite Power initiating event frequencies for normal and protected conditions.
>
> In 2002, an additional, nearby offsite power source (Sharpe Station) became available to Wolf Creek. The AC power source may be used during station blackout conditions. The 1998 PRA model was modified to make use of this new capability. Further discussion is included under RAI 5.
>
> The 1998 PRA model was modified to make use of the Sharpe Station capability. The WCGS model is constructed such that all cutsets that result in station blackout conditions are flagged. This flagging becomes a simple and effective way to consider the impact of having the Sharpe Station available to provide power to the plant through the switchyard.
>
> As a flag event (i.e., value set to unity), the "SBO" term is present in any cutset combination that constitutes a station blackout. To utilize it to modify the probability of the plant to mitigate station blackout conditions with the added capability of the Sharpe Station, the value of SBO is changed to represent the top event failure probability of supplying power to the safety buses from the Sharpe Station. One limitation to applying this modified station blackout multiplier to all cutsets that result in a SBO event is that it non-conservatively reduces the value of cutsets that are

essentially non-recoverable SBO scenarios. Such cutsets include failure of transformer XNB01 and coincident failures leading to both trains of essential service water (ESW) being functionally unavailable. These cutsets are considered non-recoverable since availability of the Sharpe Station to the switchyard does not mitigate progression to core damage. To account for this, a non-recoverable SBO fault tree was created to define these cutsets that effectively render the Sharpe Station ineffective.

Review of initiating event frequencies is a regular part of a PRA update. The Loss of Offsite Power initiating event frequency was updated for this application. The additional AC power source and the proposed extended Completion Time for DG maintenance lent itself to re-assessing the LOSP initiating event frequency following the guidance outlined in RAI 8 in Attachment II. A WOG Peer Review question impacting the 1998 PRA Model LOSP initiating event frequency is discussed in RAI 2 in Attachment II.

Values from the Brookhaven National Laboratory Technical Report W6211-08/99 (August 1999) were obtained for the higher temperature, qualified seal materials for model re-quantification.

6. This may also be considered a combined change request per RG 1.174 since credit is being taken for Sharp station - this needs to be discussed.

Response: The subject of combined change request was addressed in two letters. Letter ET 05-0016 answered Questions 15 and E.2.I.(h). Question 15 referred back to WO 03-0057 Attachment II RAI 9 on page 13.

7. The SBO CDF is less for the amendment request but mission time and diesel fail to start are greater than the IPE?

Response: The question is similar to Question 8 (below). Refer to response to Question 8.

8. Is a mission time of 7 hours adequate based on expected power recovery and considering the extend[sic] of maintenance to be performed on the out of service DG.

Response: The DG mission time was increased from a value of 2.5 hours used in the IPE, to a value of 7 hours in order to provide consistency with most other internal events PRA models. (See letter ET 05-0016, Attachment II, page 3, Item E.1.6.)

An answer is only provided to first part of question (ending in "expected power recovery") as remainder of question does not seem relevant to the first part. The mission time was not developed with either a 72-hour or a 7-day maintenance duration, or any other maintenance duration, in mind.

Diesel generator repair/recovery is not explicitly included in the Wolf Creek PRA model.

9. Has recovery for the out of service DG been modified to reflect the extended CT and additional maintenance to be performed? SE states that the licensee did not explicitly include DG repair of recovery in its PRA model. How about power recovery assumptions?

Response: Wolf Creek does not explicitly include DG repair and recovery in its PSA model. Therefore, no modification has been made to reflect the extended CT and the potential additional maintenance that may be performed.

With regard to power recovery assumptions, refer to Question 8 response and the following discussion.

The probability of recovery of offsite power is considered in the WCGS PSA model for the time periods of 2 hours and 8 hours following occurrence of a SBO event. Recovery of offsite power at 2 hours is addressed following failure of the turbine driven auxiliary feedwater (AFW) pump. If AFW fails, core uncovery can be expected to begin at approximately 2 hours. If offsite power is restored at this time, core damage can by prevented by subsequent actuation of safety injection for RCS inventory restoration. If AFW is successful and continues for 8 hours, then the probabilities are reassessed at 8 hours. The duration of 8 hours is based on the best estimate battery life to provide circuitry control power to the turbine driven auxiliary feedwater pump (TDAFWP). The TDAFWP is assumed to fail after 8 hours due to battery failure. If recovery of offsite power at 8 hours fails, then power recovery is addressed at the time when the core would begin to uncover. The times following the SBO event initiation at which the core uncovery event is addressed, given that the power recovery event has failed, depends on whether RCS cooldown was performed. If offsite power recovery for the 8 hour event fails, then power recovery is addressed at the postulated time of core uncovery of 10 hours if the RCS cooldown and depressurization function was unsuccessful and at 12 hours if the RCS cooldown and depressurization function was a success.

10. PRA uncertainty needs to be discussed - sensitivity analysis? Especially Sharp station - procedures, human actions, maintenance, reliability, maintenance rule criteria if any.

Response: The results of the PSA evaluation contain numerous conservatisms. Perhaps the most significant is the choice to reduce the test and maintenance (TM) basic event values, while protecting the plant with an DG out-of-service, by only 25%. The makeup of the TM values includes times of both planned and unplanned maintenance. Planned maintenance is completely controllable and can easily be excluded during the protected configuration of an extended DG Completion Time. Unplanned, or emergent and reactive, maintenance is in response to component degradations and/or failures and, therefore, is not entirely controllable. The bulk of most test and maintenance unavailabilities are considered to be a result of planned maintenance (and subsequent testing). Therefore, even a 50% reduction in TM unavailability values is likely still conservative. To determine the potential impact this might have on the Completion Time, as a sensitivity study all TM events were further decreased in value to 50% of their original value and re-quantified. The results from this sensitivity study are summarized in the following table and are expressed in terms of the maximum justifiable Completion Time duration based on the limiting RG 1.177 ICCDP value of 5.0E-07.

		Results	
		Protected CDF Value	Justifiable CT (per cycle)
% TM Reduced	50%	5.042E-05	8.31 days/DG
	25%	5.170E-05	7.68 days/DG

With regard to the Sharpe Station, a simple examination of the first several cutsets quickly identifies the single dominating basic event. Failure of the assumed operator action to properly energize and align the Sharpe Station to the Wolf Creek switchyard for use to mitigate a SBO event is nearly two orders of magnitude greater than the next most significant cutset (common cause failure of all gensets to run). Basis for the assumed operator action value used in this evaluation is engineering judgment. Following the original TS submittal, however, a separate Human Reliability Analysis (HRA) evaluation was performed based on the availability of the procedure for use in aligning the Sharpe Station to provide mitigation of a SBO event. This evaluation produced an operator action value of nearly one order magnitude less than the value used for the submittal.

Due to the level of conservatism assumed for the dominating operator action, a sensitivity study on any other Sharpe Station aspect would not yield useful results.

11. Additional Tier 2 compensatory measures - are they required? Emergent work evaluated? States that the Sharp station gensets will be confirmed available - what is this criteria? Grid and offsite conditions checked before and during an extended DG outage? Restrictions of maintenance/testing on operable loop / train of operable DG and support systems?

Response: Letter WO 03-0057, Attachment I page 19 (Section 4.1.1.2) discusses the Tier 2 compensatory measures and configuration risk management controls associated with an extended DG Completion Time. This information is incorporated into the proposed TS Bases for Required Actions B.4.1, B.4.2.1, and B.4.2.2. See letter ET 05-0025 Attachment IV page 8 for the latest proposed TS Bases. Letter WO 03-0057, Attachment II page 16, RAI 11 addresses determining the appropriate risk management compensatory measures when emergent work is identified.

12. Confirm that the licensee has reviewed their maintenance rule 10 CFR 50.65 CRMP and that it meets the RG 1.177 2.3.7.2 key components guidance.

Response: The Wolf Creek risk management program includes the Key Components specified in RG 1.177, subsection 2.3.7.2. The Wolf Creek risk management program implements the requirements of 10 CFR 50.65, paragraph (a)(4) that requires licensees, prior to performing maintenance activities, to assess and manage the increase in risk that may result from the proposed maintenance activities. Procedure AP 22C-003, "Operational Risk Assessment Program," delineates the requirements and expectations for performing risk assessments.

A corrective action document is generated for all equipment failures. The Shift Manager is responsible for evaluating how changing conditions (including new equipment issues) impact the plant and work in progress, including the risk associated with the condition. The Shift Manager has several options available to evaluate the risk associated with changing conditions. He can perform a qualitative assessment based on his knowledge and experience, he can use the Safety Monitor™ to assess the risk or he can request assistance from the PSA group.

13. Confirm that the any IPE or IPEEE findings, improvements, or commitments were implemented and that there were no specific findings related to the DGs and this amendment that were not resolved.

Response: All IPE recommendations, and IPEEE recommendations except one, were complete prior to this submittal. Submittal letter WO 03-0057 Attachment II, RAI 2 (page 2) identified the last IPEEE recommendation to be implemented: "The final Reactor Coolant Pump (RCP) seal upgrade is to be implemented during the upcoming Fall 2003 Refueling Outage." This was completed on schedule as described.

14. Any peer review performed on the updates to the PRA in support of the extended DG amendment? Procedure or standards referenced?

Response: The PRA model for failure to deliver AC power from the Sharpe Station to the Wolf Creek plant was developed by the WCNOC PRA group. The PRA one-line drawing representing Sharpe Station was presented in ET 05-0016, Attachment I, Question 25, page 15. Representatives of the WCNOC PRA group, along with other WCNOC personnel, visited the Sharpe Station several times with the utility engineer responsible for the Sharpe Station. These visits were undertaken to gain an understanding of the capabilities and operation of the station. Questions were asked of the utility engineer responsible for the Sharpe Station with emphasis on identification of possible "pinch points", or single failures, that might result in failure of the station to deliver AC power to the Wolf Creek plant.

The PRA model for the Sharpe Station was developed based on these visits to the station and discussions with the utility engineer responsible for the station. As questions arose during development of the Sharpe Station PRA model, clarification was provided by the responsible utility engineer, and the PRA model was refined accordingly. In the absence of station specific experience, generic industry component failure rate data was utilized in the Sharpe Station PRA model.

The Sharpe Station PRA model, and associated evaluation for the extended DG Completion Time was reviewed by a second, independent WCNOC PRA analyst, and by a Group supervisor. This followed the regular calculation approval process used for Engineering and Safety Analysis. Cutsets from quantification of the Sharpe Station PRA model were included in the reviews. Expected top cutsets reflecting station design were readily observed. A key parameter in the extended DG Completion Time evaluation, providing greater impact than the Sharpe Station design, was the loss of offsite power initiating event frequency. WCNOC addressed this parameter by committing to perform the pre-planned maintenance period during historically low periods of grid disturbance and severe weather.

The Sharpe Station PRA model was not subjected to a formal outside peer review. However, a meeting was held with another utility's PRA personnel preparing a similar change request of a similar design plant. The meeting purpose was to resolve apparent result differences through discussion of assumptions and modeling. The level of knowledge in this utility's PRA group, relative to Sharpe Station configuration and operation, was limited to that included in the completion time extension evaluation provided to them. No comments relative to the structure of the Sharpe Station PRA model were provided. Critical discussions during the meeting served the same function as would occur during a more formal Peer Review.

The WCNOC PRA analysts and PRA group supervisor involved in the development and review of the Sharpe Station PRA model are cognizant of Facts & Observations (F&Os) resulting from the WOG Peer Review of the WCGS PRA model. These F&Os were considered during the development and review of the Sharpe Station PRA model as indicated in WO 03-0057, Attachment II, RAI 2, page 1, and ET 05-0016, Attachment II, Question E.2.I.(e), page 4.

15. Shutdown discussion that concludes that performing DG maintenance outside the outage can be significant on shutdown risk - this depends on the time of DG maintenance during the outage and can be quite misleading - suggest that this is not a basis for extension and should be removed or this section expanded to include the basis for the conclusion.

Response: Letter WO 03-0057, Attachment II page 18 RAI 12 addresses this subject and is summarized in the last sentence of the WOG Response: "As demonstrated in the WCAP and in responses to RAIs #8 and #16, the impact of the Completion Time increase on risk (CDF, LERF, ICCDP, and ICLERP) meets the guidelines provided in Regulatory Guides 1.174 and 1.177, therefore, the argument for the acceptability of this change is based on the low impact of this change on at-power plant risk, not the tradeoff with shutdown risk."

The paragraphs were included as a reasoned, qualitative discussion of risk in modes other than power operation. The conclusions of meeting the risk metrics are not altered if the discussion on DG maintenance risk during shutdown/refueling is eliminated.

16. Was the risk determined based on a 7 day CT or 10 days? Should it be 10 days based on the LCO 3.8.1?

Response: *The risk was determined based on a 7 day Completion Time as the 10 day* Completion Time is the "second Completion Time." WCNOC letter ET 05-0016, Attachment I, page 17 (Question 27) discusses the second Completion Times, how they are determined, and that the NRC agreed that the second Completion Time was not required to be risk informed. Additionally, the NRC has approved Rev. 3.1 to the Improved Standard Technical Specification that incorporates TSTF-449 which eliminates the second Completion Times. WCNOC is considering a license amendment at a later date to adopt TSTF-449.

17. For the proposed amendment, address whether the risk numbers given for the extended CTs for (1) the inoperable DG and (2) the inoperable vital ac bus should be combined or are they separate risk numbers. RG 1.174 has a discussion on combined license change request risk. This question may be in Question 6 [renumbered to Question 10] sent to you earlier.

Response: The response to Question 6 (above) has already addressed combined risk. However, as discussed in the cover letter, WCNOC is withdrawing the proposed change to the AC vital bus Completion Time.

18. To clarify Question 5, provide the risk for (1) the inoperable DG and (2) the inoperable vital ac bus with and without credit for the Sharpe Station.

Response:

With Sharpe Station Credited

DG		Normal*	Protected*
	CDF	3.485E-05	5.170E-05
	LERF	7.735E-07	1.169E-06

AC Bus		
	CDF	1.714E-04
	LERF	2.740E-06

Without Sharpe Station Credited

DG		Normal*	Protected*
	CDF	5.173E-05	1.563E-04
	LERF	7.796E-07	1.354E-06

AC Bus		
	CDF	1.491E-04
	LERF	2.734E-06

*NOTE:
Normal refers to "everyday" operation configuration of the plant with no specific compensatory measures in effect (such as described in Section 4.1.1.2 of the submittal).
Protected refers to a plant configuration implementing additional compensatory measures for the purpose of an extended DG outage.

19. Address if the PRA analysis that credits the Sharpe Station includes a common cause failure for the four gensets needed.

Response: A common cause term is included for each genset at Sharpe Station. These common cause terms are then combined in the fault tree logic to obtain failure combinations. Individual common cause terms were developed for 2 out of 5 gensets, 3 out of 5 gensets, 4 out of 5 gensets, and 5 out of 5 gensets. Additionally, it is assumed that the probability of 5 out of 5 gensets equals the probability of ALL gensets being unavailable. This is a conservatism that has significant impact to this evaluation as it results in the second largest cutest generated.

Refer to Table 8-2 of the WO 03-0057 (page 16 of 23 to Attachment I), "Summary of Important PRA Assumptions and Modeling Features Relevant to the DG and DG CCF Completion Time Extensions," for common cause values used in modeling the Sharpe Station.

20. Address what happens with respect to the common cause evaluation (current TS 3.8.1 Required Action B.3.1) if, in the extended DG CT, it is determined that the DG is broken.

Response: The 7 day Completion Time is utilized for preplanned scheduled maintenance. Therefore, the DG is considered OPERABLE prior to declaring LCO 3.8.1 not met and entry into Condition B. At the point that the DG is declared inoperable, Condition B is entered and Required Actions B.1 would be performed, then B.2, and then B.3.1 or B.3.2. In this case,

there would be no common cause because there were no failures upon the entry into Condition B. The Completion Time on Required Action B.3.1 is 24 hours, which means that it only has to be performed once. However, if during the preplanned maintenance activities a failure of a component were identified, use of prudent operational and engineering practices result in questioning the OPERABILITY of the other train. Technical Specifications themselves would not require performance of B.3.1 if a failure were found during the actual maintenance activities.

21. As part of the Tier 3 assessment, address how the risk monitor is used in the CRMP.

Response: The guidance to assess and manage risk prior to performing maintenance at Wolf Creek is controlled by procedure AP 22C-003, "Operational Risk Assessment Program." The risk assessment process consists of the following general steps:

1. Weekly work schedule Rev. 0 is issued approximately 2 weeks prior to planned workweek.
2. Integrated Plant Scheduling (IPS) performs a qualitative defense-in-depth assessment on the rev. 0 schedule using AP 22C-003.
3. The weekly schedule and the IPS risk assessment is provided to the Shift Manager (SM) for review and comment.
4. The risk assessment is updated by IPS (if necessary) and then sent to the PSA group along with the weekly schedule.
5. The PSA group reviews the weekly schedule and performs a quantitative risk assessment using the Safety Monitor™approximately one week prior to the work being performed. The PSA group signs the IPS assessment, provides a risk profile for the week's activities and any recommendations based on their insights to IPS.
6. IPS forwards the weekly schedule and associated risk assessments to the Plant Manager for review and concurrence is signified by signing the schedule.
7. The schedule and risk assessments are returned to IPS to implement the work schedule.
8. The SM has the responsibility to ensure the conditions assumed in the risk analysis exist prior to allowing work to start. If conditions have changed, the SM can perform his own risk assessment of the situation (qualitative or quantitative) or request the PSA group perform a new assessment.

The Safety Monitor™ is used by the PSA group as part of their review of the rev. 0 weekly schedule. The Safety Monitor™ can also be utilized by the Shift Manager to perform an assessment of changing conditions.

22. Address if the fire risk changes because of the extended CTs for (1) the inoperable DG and (2) the inoperable vital ac bus.

Response: The alignment for delivery of power from the Sharpe Station to either or both ESF buses is through ESF transformer XNB01. Fires that would impact XNB01, or the supply cables from XNB01 to ESF buses NB01 or NB02, would prevent delivery of power from the Sharpe Station. See letter WO 3-0057, Attachment I (page 4 of 23) for a simplified one line diagram of the electrical power distribution system.

All of the fire areas impacting XNB01, or the supply cables from XNB01 to NB01 or NB02, were screened out in the fire risk evaluation performed for the IPEEE using the EPRI FIVE methodology.

For the fire areas impacting XNB01, or the supply cables from XNB01 to NB01 or NB02, the Conditional Core Damage Probability (CCDP) was requantified with the unavailability values for the DGs adjusted to account for the extended DG Completion Time. Using the requantified CCDP, the frequency of core damage due to a fire in the area was determined in accordance with the methodology of the original fire risk evaluation. For all of these fire areas, the core damage frequency due to a fire in the area using the requantified CCDP, met the screening criteria using the EPRI FIVE methodology. (i.e., a full PRA of the fire area was not required).

For fire areas where XNB01, or the supply cables from XNB01 to NB01 or NB02, are not impacted, the delivery path for power from the Sharpe Station to either or both ESF buses would remain available. For fire areas where the delivery path for power from the Sharpe Station to either or both ESF buses remain available, the risk benefit realized from having the Sharpe Station power supply available more than offsets the risk increase due to the extended DG Completion Time.

23. Address if the findings and observation weaknesses for (1) the IPE/IPEEE and (2) the updates to the IPE/IPEEE have been resolved or, if not, they are not applicable to the proposed amendment.

Response: Question 13, answered above, contained resolutions that affected both plant hardware and risk model changes, while Question 23 is understood to go more toward risk modeling issues. Findings and weaknesses identified in the IPE and IPEEE have been resolved.

ATTACHMENT II

MARKUP OF TECHNICAL SPECIFICATION PAGES

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	-------------NOTE------------ The Required Action of B.3.2 is satisfied by the automatic start and sequence loading of the DG. -------------------------------	
		Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
-------NOTE-------- Required Action B.4.2.1 and B.4.2.2 are only applicable for planned maintenance and may be used once per cycle per DG. ------------------------	AND		
	B.4.1	Restore DG to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
INSERT 1			

(continued)

INSERT 2

INSERT 1

		<u>OR</u>	
	B.4.2.1	Verify the required Sharpe Station gensets are available.	Once per 12 hours
	<u>AND</u>		
	B.4.2.2	Restore DG to OPERABLE status.	7 days <u>AND</u> 10 days from discovery of failure to meet LCO

INSERT 2

C. Required Action B.4.2.1 and associated Completion Time not met.	C.1	Restore DG to OPERABLE status.	72 hours

ATTACHMENT III

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES
(For Information Only)

BASES

ACTIONS

<u>B.4.1, B.4.2.1, and B.4.2.2</u> (continued)

required 72 hours, ~~T~~this could lead to a total of 144 hours, since initial failure to meet the LCO, to restore ~~the Dg~~**compliance with the LCO (i.e., restore the DG).** At this time, an offsite circuit could again become inoperable~~, the DG restored OPERABLE,~~ and an additional 72 hours ~~(for a total of 9 days)~~ allowed prior to complete restoration of the LCO. **Although highly unlikely, this could occur indefinitely if not limited.** The 6 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. **This limits the time the plant can alternate between Conditions A, B, and E (see Completion Time Example 1.3-3).** The "<u>AND</u>" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

Tracking the 6 day Completion Time is a requirement for beginning the Completion Time "clock" that is in addition to the normal Completion Time requirements. With respect to the 6 day Completion Time, the "time zero" is specified as beginning at the time LCO 3.8.1 was initially not met, instead of at the time Condition B was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition B "time zero," and the "time zero" when LCO 3.8.1 was initially not met. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO portion of the Completion Time."

The Required Actions are modified by a Note that states that Required Actions B.4.2.1 and B.4.2.2 are only applicable for voluntary planned maintenance and may be used once per cycle per DG. Required Actions B.4.2.1 and B.4.2.2 only applies when a DG is declared or rendered inoperable for the performance of voluntary, planned maintenance activities. Required Action B.4.2.1 provides assurance that the required Sharpe Station gensets are available when a DG is out of service for greater than 72 hours. The availability of the required gensets are verified once per ~~24 hours by contacting KEPCo personnel for the status of the units.~~ 12 hours by locally monitoring various genset parameters.

ACTIONS

B.4.1, B.4.2.1, and B.4.2.2 (continued)

The 7-day Completion Time of Required Action B.4.2.2 is a risk-informed allowed outage time (AOT) based on a plant-specific risk analysis (Ref. 15). The Completion Time was established on the assumption that it would be used only for voluntary planned maintenance, inspections and testing. Use of Required Actions B.4.2.1 and B.4.2.2 are limited to once within an operating cycle (18 months) for each DG. Administrative controls applied during use of Required Action B.4.2.2 for voluntary planned maintenance activities ensure or require that:

a. Weather conditions are conducive to an extended DG Completion Time. The extended DG Completion Time applies during the period of September 6 through April 22.

b. The offsite power supply and switchyard condition are conducive to an extended DG Completion Time, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed that would challenge offsite power availability.

c. Prior to relying on the required Sharpe Station gensets, the gensets are started and proper operation verified (i.e., the gensets reach rated speed and voltage). The Sharpe Station is not required to be operating the duration of the allowed outage time of the DG, however, it shall be capable of providing greater than 8 MW power to a dead bus (station blackout conditions) to power 1 ESF train.

INSERT B 3.8.1-12

d. No equipment or systems assumed to be available for supporting the extended DG Completion Time are removed from service. The equipment or systems assumed to be available (including required support systems, i.e., associated room coolers, etc.) are as follows:

- **Auxiliary Feedwater System (three trains)**
- **Component Cooling Water System (both trains and all four pumps)**
- **Essential Service Water System (both trains)**
- **Emergency Core Cooling System (two trains).**

INSERT B 3.8.1-12

Within 8 months prior to utilization of Required Action B.4.2.2, a load capability test/verification will be performed on the Sharpe Station gensets. The load capability testing/verification will consist of either crediting a running of the gensets for load for commercial reasons for greater than 1 hour or tested by loading of the gensets for greater than 1 hour to a load equal to or greater than required to supply safety related loads in the event of a station blackout.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. USAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3.
4. USAR, Chapter 6.
5. USAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, Rev. 0, January 1978.
11. ANSI C84.1-1982.
12. IEEE Standard 308-1978.
13. Configuration Change Package (CCP) 08052, Revision 1, April 23, 1999.
14. Amendment No. 161, April 21, 2005.
15. ~~**WCNOC letter WO 03-0057 dated October 30, 2003.**~~

Amendment No. xxx, [date].

ATTACHMENT IV

PROPOSED OPERATING LICENSE CONDITIONS

(7) NUREG-0737 Supplement 1 Conditions (Section 22, SER)

Deleted per Amendment No. 141.

(8) Post-Fuel-Loading Initial Test Program (Section 14, SER Section 14, SSER #5)

Deleted per Amendment No. 141.

(9) Inservice Inspection Program (Sections 5.2.4 and 6.6, SER)

Deleted per Amendment No. 141.

(10) Emergency Planning

Deleted per Amendment No. 141.

(11) Steam Generator Tube Rupture (Section 15.4.4, SSER #5)

Deleted per Amendment No. 141.

(12) LOCA Reanalysis (Section 15.3.7, SSER #5)

Deleted per Amendment No. 141.

(13) Generic Letter 83-28

Deleted per Amendment No. 141.

(14) Surveillance of Hafnium Control Rods (Section 4.2.3.1 (10), SER and SSER #2)

Deleted per Amendment No. 141.

(15) Additional Conditions

The Additional Conditions contained in Appendix D, as revised through Amendment No. ~~123~~ **[TBD]**, are hereby incorporated into this license. Wolf Creek Nuclear Operating Corporation shall operate the facility in Accordance with the Additional Conditions.

D. Exemptions from certain requirements of Appendix J to 10 CFR Part 50, and from a portion of the requirements of General Design Criterion 4 of Appendix A to 10 CFR Part 50, are described in the Safety Evaluation Report. These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. Therefore, these exemptions

Amendment Number	Additional Condition	Implementation Date
123	For SRs that existed prior to this amendment whose intervals of performance are being extended, the first extended surveillance interval begins upon completion of the last surveillance performed prior to implementation of this amendment.	This amendment shall be implemented by December 31, 1999.
TBD	The licensee will perform a one-time load acceptance test of the Sharpe Station prior to the first use of the 7-day Completion Time of Required Action B.4.2.2 of TS 3.8.1. The test shall utilize a nearby large motor for the purposes of simulating a large plant load. This test will be performed in conjunction with a dynamic voltage flow analysis.	Prior to the first use of the 7-day Completion Time of Required Action B.4.2.2 of TS 3.8.1.
TBD	The licensee will coordinate with KEPCo to ensure the load capability testing/verification is performed within 8 months prior to utilization of the 7-day Completion Time of Required Action B.4.2.2 in TS 3.8.1. The load capability testing/verification will consist of either crediting a running of the gensets for load for commercial reasons for greater than 1 hour or tested by loading of the gensets for greater than 1 hour to a load equal to or greater than required to supply safety related loads in the event of a station blackout.	Prior to the use of the 7-day Completion Time of Required Action B.4.2.2 of TS 3.8.1.

LIST OF COMMITMENTS

The following table identifies those actions committed to by WCNOC in this document. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. Kevin Moles at (620) 364-4126.

COMMITMENT	Due Date/Event
WCNOC will coordinate with KEPCo, to ensure a fuel oil vendor is available to provide fuel oil to the Sharpe Station on an as needed basis.	Prior to first use of exercising the 7-day Completion Time for pre-planned maintenance activities.
Administrative controls applied during use of Required Action B.4.2.2 for voluntary planned maintenance activities ensure or require that: a. Weather conditions are conducive to an extended DG Completion Time. The extended DG Completion Time applies during the period of September 6 through April 22. b. The offsite power supply and switchyard condition are conducive to an extended DG Completion Time, which includes ensuring that switchyard access is restricted and no elective maintenance within the switchyard is performed that would challenge offsite power availability. c. Prior to relying on the required Sharpe Station gensets, the gensets are started and proper operation verified (i.e., the gensets reach rated speed and voltage). The Sharpe Station is not required to be operating the duration of the allowed outage time of the DG, however, it shall be capable of providing greater than 8 MW power to a dead bus (station blackout conditions) to power 1 ESF train. Within 8 months prior to the utilization of Required Action B.4.2.2, a load capability test/verification will be performed on the Sharpe Station gensets. The load capability testing/verification will consist of either crediting a running of the gensets for load for commercial reasons for greater than 1 hour or tested by loading of the gensets for greater than 1 hour to a load equal to or greater than required to supply safety related loads at WCGS in the event of a station blackout.	Prior to exercising the 7-day Completion Time for pre-planned maintenance activities.

COMMITMENT	Due Date/Event
d. No equipment or systems assumed to be available for supporting the extended DG Completion Time are removed from service. The equipment or systems assumed to be available (including required support systems, i.e., associated room coolers, etc.) are as follows: • Auxiliary Feedwater System (three trains) • Component Cooling Water System (both trains and all four pumps) • Essential Service Water System (both trains) • Emergency Core Cooling System (two trains). Procedure SYS KJ-200, "Inoperable Emergency Diesel," will include the administrative controls associated with the utilization of the 7-day Completion Time of Required Action B.4.2.2 in TS 3.8.1.	
Inclusion of the risk impact of the Sharpe Station in the Safety Monitor™ will be accomplished prior to the first utilization of the extended DG Completion Time. An activity will be added to the Activity Table of the Safety Monitor™ that will account for the impact of the plant configuration associated with crediting the Sharpe Station during use of the subject DG extended Completion Time.	Prior to first use of exercising the 7-day Completion Time for pre-planned maintenance activities.
WCNOC will perform a one-time load acceptance test of the Sharpe Station gensets. The one-time load acceptance test will be performed prior to the first use of the 7-day Completion Time for pre-planned maintenance activities. The test will demonstrate the capability of the Sharpe Station to successfully start a large motor (1500 hp motor at a nearby gas pumping station) to simulate nuclear plant loads at WCGS. Additionally, a dynamic voltage flow analysis will be performed, using vendor provided test data for starting large motor loads, to further demonstrate from an analysis perspective that the Sharpe Station would be capable of starting and carrying designated loads, including maintaining adequate voltage and frequency such that performance of powered equipment would be acceptable. This statement means that the analysis will demonstrate that the Sharpe Station genset are capable of starting and carrying designated loads and that the voltage and frequency would be adequate to ensure no damage to equipment and that degraded voltage and loss of voltage functions are not challenged.	Prior to first use of exercising the 7-day Completion Time for pre-planned maintenance activities.