Stephen L. Smith
Engineering Vice President

September 29, 2021

ET 21-0004

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

Subject: Docket No. 50-482: License Amendment Request – Diesel Generator Completion Time Extension for Technical Specification 3.8.1, "AC Sources – Operating"

Commissioners and Staff:

In accordance with the provisions of Title 10 of the Code of Federal Regulations (10 CFR Part 50.90), "Application for amendment of license, construction permit, or early site permit," Wolf Creek Nuclear Operating Corporation (WCNOC) is submitting a request for an amendment to the technical specifications (TSs) for the Wolf Creek Generating Station (WCGS). The proposed amendment would modify WCGS Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time for one inoperable diesel generator (DG) from 72 hours to 14 days based on the availability of a supplemental power source (i.e., Station Blackout DG System).

The proposed amendment represents a deterministic based amendment supplemented by risk insight information. The proposed amendment has been developed using the guidelines established in Branch Technical Position 8-8, "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions," Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and Regulatory Guide 1.177, "Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

Attachment I provides a description and technical basis for the proposed change. Attachment II provides the risk assessment to support the DG Completion Time extension. Attachment III provides the existing TS pages marked up to show the proposed change. Attachment IV provides revised (clean) TS pages. Attachment V provides the existing operating license pages marked up to show the proposed change. Attachment VI provides revised (clean) operating license pages. Attachment VII provides the proposed TS Bases changes for information only. Attachment VIII provides a list of regulatory commitments. Attachment IX provides a discussion of the conformance with the guidance contained in Nuclear Regulatory Commission (NRC) Branch Technical Position 8-8.

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WCNOC requests approval of this license amendment request by September 6, 2022. The license amendment, as approved, will be effective upon issuance and will be implemented within 90 days from the date of issuance.

In accordance with 10 CFR 50.91, “Notice for public comment; State consultation,” Section (b)(1), a copy of this amendment application, with Attachments, is being provided to the designated Kansas State official.

If you have any questions concerning this matter, please contact me at (620) 364-4156, or Ron Benham at (620) 364-4204.

Sincerely,

Stephen L. Smith

SLS/rlt

Attachments:	I	Evaluation of the Proposed Change
	II	Risk Assessment to Support Diesel Generator Completion Time Extension
	III	Proposed Technical Specification Changes (Mark-up)
	IV	Revised Technical Specification Pages
	V	Proposed Operating License Changes (Markup)
	IV	Revised Operating License Changes
	VII	Proposed TS Bases Changes (for information only)
	VIII	List of Regulatory Commitments
	IX	Implementation of Branch Technical Position 8-8

cc: S. S. Lee (NRC), w/a
S. A. Morris, (NRC), w/a
N. O’Keefe (NRC), w/a
K. S. Steves (KDHE), w/a
Senior Resident Inspector (NRC), w/a

STATE OF KANSAS)
) SS
COUNTY OF COFFEY)

Stephen L. Smith, of lawful age, being first duly sworn upon oath says that he is Vice President Engineering 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 [signature]
Stephen L. Smith
Vice President Engineering

SUBSCRIBED and sworn to before me this 29th day of September , 2021.

RHONDA L. TIEMEYER
Notary Public, State of Kansas
My Appointment Expires
January 11, 2022

Rhonda L. Tiemeyer
Notary Public

Expiration Date January 11, 2022

EVALUATION OF PROPOSED CHANGE

Subject: License Amendment Request – Diesel Generator Completion Time Extension for Technical Specification 3.8.1, "AC Sources – Operating"

EVALUATION OF PROPOSED CHANGE

1.0 SUMMARY DESCRIPTION

Wolf Creek Nuclear Operating Corporation (WCNOC) letter dated October 30, 2003 (Reference 6.1) requested changes to the Wolf Creek Generating Station (WCGS) Technical Specifications (TS). The requested changes to diesel generator (DG) Limiting Conditions for Operation (LCO) Required Actions would revise the 72 hour Completion Time specified in TS 3.8.1, "AC Sources – Operating. Specifically, the revised TS included Required Actions and Completion Times that allowed 7 days to restore an inoperable DG that was taken out of service for voluntary planned maintenance activities. The risk-informed justification for the 7 day Completion Time was based on the availability of the Sharpe Station gensets that are located approximately two miles north of WCGS. By letter dated April 26, 2006 (Reference 6.2), the Nuclear Regulatory Commission (NRC) issued Amendment No. 163 to WCGS Facility Operating License No. NPF-42 to increase the Completion Time and add requirements on the gensets at the Sharpe Station in TS 3.8.1.

The proposed amendment revises WCGS TS 3.8.1, "AC Sources –Operating," by removing the requirements associated with the Sharpe Station gensets and extending the Completion Time in Required Action B.4.1 for one inoperable DG from 72 hours to 14 days based upon the availability of a supplemental AC power source (i.e., Station Blackout (SBO) DG System). The proposed changes will provide operational and maintenance flexibility. The proposed changes will provide sufficient time to perform planned and emergent maintenance activities that cannot be performed within a 72 hour Completion Time.

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, "Additional Conditions," by deleting the license conditions associated to Amendment No. 163.

The proposed new Completion Time is based on the WCNOC deterministic justification and risk insights provided in this attachment and Attachment II, additional considerations and compensatory measures, and is consistent with the 14 day Completion Time permitted in Branch Technical Position (BTP) 8-8 (Reference 6.3).

2.0 DETAILED DESCRIPTION

2.1 Current Technical Specification Requirements and Operating License Conditions

TS 3.8.1 Required Action B.4.1 applies when a DG is discovered or determined to be inoperable with a Completion Time of 72 hours to restore the DG to operable status. Required Actions B.4 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 7 day Completion Time of Required Action B.4.2.2 is a risk-informed allowed outage time based on a plant-specific risk analysis. The Completion Time was established on the assumption that it would be used only for voluntary planned maintenance, inspections and testing.

TS 3.8.1 Condition C requires the restoration of the inoperable DG to operable status with a Completion Time of 72 hours if Required Action B.4.2.1 and associated Completion Time is not met.

With the issuance of Amendment No. 163, three (3) license conditions were added to Appendix D of the operating license. The first license condition required the performance of a one-time load acceptance test of the Sharpe Station gensets prior to the first use of the 7 day Completion Time of Required Action B.4.2.2. The second license condition required the coordination with KEPCo to ensure a load capability testing/verification was performed within 8 months prior to the utilization of the 7 day Completion Time of Required Action B.4.2.2. The third license condition required including a specific reactor coolant pump (RCP) seal model in the 2002 WCGS Probabilistic Safety Assessment (PSA) Model and including the risk impact of the Sharpe Station gensets in the safety monitor prior to the first use of the 7 day Completion Time of Required Action B.4.2.2.

2.2 Reason for the Proposed Change

The TS changes are being requested to provide sufficient time to perform planned DG preventative maintenance and surveillance testing to ensure DG reliability and availability.

The proposed changes also provide flexibility to resolve emergent DG deficiencies and avoid a potential unplanned plant shutdown and associated thermal transient, along with the potential challenges to safety systems during an unplanned shutdown, should a condition occur requiring DG corrective maintenance. On June 28, 2020, the NRC approved WCNOC's verbal request for enforcement discretion for an additional 22 hours to complete repairs and testing on the 'B' DG room supply fan and restore the 'B' DG to operable status. On January 10, 2013, the NRC approved WCNOC's verbal request for enforcement discretion for an additional 96 hours to complete repairs and testing for a broken cylinder head stud and restore the 'B' DG to operable status. A request for notice of enforcement discretion would not have been required if WCNOC had previously obtained approval for an extended DG Completion Time.

The main purpose of the proposed changes is to extend the TS Completion Time for an inoperable DG from 72 hours to 14 days. The 14 day Completion Time is requested to (1) provide the necessary time to support planned DG preventative maintenance and surveillance testing, and (2) reduce the likelihood and unnecessary burden of a plant shutdown should an unplanned DG outage occur with the plant at power by providing additional time to repair and reestablish operability of the inoperable DG. BTP 8-8 specifies that a supplemental power source be available as a backup to the inoperable DG or offsite power source, to maintain the defense-in depth design philosophy of the electrical system to meet its intended safety function. A SBO DG System is provided for improved nuclear plant safety resulting in Mitigating Systems Performance Index (MSPI)/Probabilistic Risk Assessment (PRA) margin. (See Section 3.4 below for additional details of the SBO DG System.) The SBO DG System consists of three non-safety related DGs that are capable of supplying essential loads on Class 1E busses NB01 or NB02. Busses NB01 and NB02 feed two redundant load groups that are each capable of safely shutting down the plant.

2.3 Description of Proposed Changes

2.3.1 Proposed TS Changes

The proposed TS changes provide consistency within the existing WCGS TSs and with the guidance in TS Section 1.3, "Completion Times."

2.3.1.1 <u>Changes to Condition A</u>

The Note to the Required Action A.3 72 hour Completion Time is deleted. WCNOC will no longer be relying on the use of the Sharpe Station gensets with the approval of the proposed license amendment. A plant modification is under development that will result in removal of the capability to align the Sharpe Station as a backup to the DGs. The maximum Completion Time for Required Action A.3 is proposed to be extended from 6 days to 17 days. The maximum Completion Time limits the total time that LCO 3.8.1 is not met while concurrently or simultaneously in Condition A and the proposed new Required Action B.5. Currently, this Completion Time is the sum of the Completion Time for existing Required Action A.3 (i.e., 72 hours) and Required Action B.4.1 (i.e., 72 hours). The proposed new Required Action B.5 will allow one DG to be inoperable for up to 14 days, if the required SBO DGs are available. Therefore, the maximum Completion Time for Required Action A.3 will be increased from 6 days to 17 days.

2.3.1.2 <u>Changes to Condition B</u>

The following is proposed to be added as new Required Action B.2:

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One DG inoperable.	<u>AND</u>		
	B.2	Verify the required Station Blackout (SBO) DGs are available.	1 hour <u>AND</u> Once per 8 hours thereafter

Proposed Required Action B.2 is a new action. The proposed action requires verifying the availability of the required SBO DGs. The availability of the required SBO DGs supports the extended Completion Time included in proposed Required Action B.5 discussed below. Unavailability of the required SBO DGs does not, by itself, result in the LCO not being met.

The existing Required Action B.2 is renumbered to B.3. Required Actions B.3.1 and B.3.2 are renumbered to Required Actions B.4.1 and B.4.2. The existing Required Action B.3.2 Note is revised to refer to the renumbered Required Action B.4.2.

The following is the proposed new Required Action B.5 (existing Required Actions B.4.1, B.4.2.1 and B.4.2.2). The proposed changes revise the existing TSs for the use of the required SBO DGs for the extended Completion Time and eliminate the actions associated with the use of the Sharpe Station gensets.

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One DG inoperable.	<u>AND</u> B.5 Restore DG to OPERABLE status.	14 days <u>AND</u> 17 days from discovery of failure to meet the LCO

The first Completion Time of 72 hours is revised to 14 days and limits the overall Completion Time to 14 days when the required SBO DGs are available. The second Completion Time is the second Completion Time in the existing Required Action B.4.1 and, similar to Required Action A.3, is proposed to be extended from 6 days to 17 days with an "AND" meaning it applies simultaneously to the first Completion Time. The effect is to limit the total time that LCO 3.8.1 may not be met while concurrently or simultaneously in Conditions A and B.

2.3.1.3 Changes to Condition C

The following is the proposed Condition C, Required Action C.1, and associated Completion Times. Condition C is revised to reflect the unavailability of the required SBO DG(s) when a DG is inoperable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action B.2 and associated Completion Time not met.	C.1 Restore DG to OPERABLE status or restore required SBO DGs to available status.	72 hours from discovery of unavailability of required SBO DGs OR 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of required SBO DGs

The addition of the words "from discovery of unavailability of the required SBO DGs" apply when the required SBO DGs are unavailable as determined by Required Action B.2. The purpose of the second new proposed Completion Time is to limit the Completion Time to 24 hours if the required SBO DGs are discovered to be unavailable at greater than or equal to 48 hours after entering Condition B. The Completion Times are connected by an "OR" logical connector to reflect the timing of when a required SBO DG is determined to be unavailable.

2.3.1.3 Changes to H

Existing TS Condition H is revised to reflect the changes to Condition B.

2.3.2 Changes to the Renewed Facility Operating License

The three license conditions added to Appendix D of the operating license with the issuance of Amendment No. 163 are deleted. The first license condition required the performance of a one-time load acceptance test of the Sharpe Station gensets prior to the first use of the 7 day Completion Time of Required Action B.4.2.2. The second license condition required the coordination with KEPCo to ensure a load capability testing/verification was performed within 8 months prior to the utilization of the 7 day Completion Time of Required Action B.4.2.2. The third license condition required including a specific RCP seal model in the 2002 WCGS Probabilistic Safety Assessment (PSA) Model and including the risk impact of the Sharpe Station gensets in the safety monitor prior to the first use of the 7 day Completion Time of Required Action B.4.2.2.

2.4 Bases for the Proposed Change

2.4.1 DG Allowed Outage Time

The purpose of the proposed change is to extend the TS Completion Time (allowed outage time) for an inoperable DG from 72 hours to 14 days. The 14 day Completion Time is necessary to (1) provide the time to support planned preventative maintenance, and (2) reduce the likelihood and unnecessary burden of a plant shutdown should an unplanned DG outage occur with the plant at power by providing additional time to repair and reestablish operability of the inoperable DG. To justify the 11 day extension, two SBO DGs that are capable of powering one 4.16 kV Class 1E buses (NB01 or NB02) during a loss of offsite power (LOOP) are required. A SBO DG System is provided for improved nuclear plant safety resulting in MSPI/PRA margin. At least two of the SBO DGs will be available to power one 4.16 kV Class 1E bus during the extended DG Completion Time.

The current practice is to perform three on-line maintenance outages per 18 months per train, using the Required Action B.4.1 Completion Time of 72 hours. The outage durations are typically scheduled for a maximum of 36 hours or 50% of the Completion Time in accordance with procedure AP 22C-002, “Work Controls.” Additionally, on-line maintenance is performed using the 7 day Completion of Required Action B.4.2.2 once per 18 months per train. The outage duration is scheduled for 84 hours. The on-line maintenance outages encompass maintenance on equipment conditions identified during the operating cycle, that do not affect operability, and longer periodicity preventative maintenance activities. For example, in October 2020, the planned 7 day Completion Time outages include replacing the ‘A’ DG jacket water keep warm pump mechanical seal, inspection and replacement (as necessary) flexible hoses; replacement of the zinc anodes and Smith Blair coupling gaskets on the ‘A’ DG; replacement of thermostatic valve elements on the ‘B’ DG; polarization index testing on cables on the ‘B’ DG; cleaning, inspection, and eddy current testing the jacket water heat exchangers; and replacement of left and right bank air start valves.

In accordance with procedure MPM M018Q-01, “Standby Diesel Generator Inspection,” minor maintenance and major maintenance is performed during refueling outages. Minor maintenance includes activities, such as:

- Borescope Cylinder Liners
- Connecting Rod Bearing Inspection
- Crankcase Inspection
- Cylinder Liner Lower End Inspection
- Engine Pressure Test
- Exhaust Gasket Inspection
- Fuel Rack Control Linkage Inspection
- Governor Inspection and Maintenance
- Injection Nozzle Inspection
- Main Bearing Tightness Inspection
- Overspeed Trip Mechanism Inspection and Cleaning

WCNOC plans to move the minor maintenance activities to be performed on-line and included as part of maintenance activities conducted during a 14 day Completion Time outage. The minor maintenance activities in conjunction with the activities currently performed during the 7 day Completion Time outage would result in an expected outage duration of approximately 162 hours.

The extended Completion Time, to allow a DG to be removed from service for 14 days to perform preventative maintenance or to perform corrective maintenance resulting from an emergent condition, are acceptable from a risk-informed approach due to a small increase in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) consistent with the criteria in Regulatory Guides (RG) 1.174 and 1.177 (References 6.10 and 6.11). The results of the risk assessment are provided in Section 3.9.

A 14 day Completion Time is justifiable as a contingency provision for unexpected DG failures and minimizes the need for expedited licensing actions seeking approval of additional time beyond the current 72 hour Completion Time (e.g., enforcement discretion). As discussed in Section 2.2 above, WCNOC has previously requested enforcement discretion. The January 2013 request resulted in a DG being out of service for approximately 114 hours. The June 2020 request resulted in the DG being out of service for approximately 84 hours. In December 2010, WCNOC removed the ‘A’ DG from service to perform planned maintenance under the Required Action B.4.2.2 Completion Time of 7 days. Excessive emergent work activities resulted in the inability to return the DG to operable status within the required Completion Time and a plant shutdown was conducted (Reference 6.12). The total out of service time during this event was approximately 212 hours.

Given the conclusions reached by the evaluations that follow, extending the Completion Time associated with an inoperable DG provides for the efficient use of resources. The extended Completion Time, to permit a DG to be removed from service for 14 days to perform planned preventative maintenance or to perform corrective maintenance resulting from an emergent condition while the plant is in MODE 1-4, will avert unplanned unit shutdowns and minimize the potential need for expedited licensing actions seeking approval of additional time to complete repairs. This change will allow maintenance activities that improve DG reliability to be performed on-line that would otherwise require performance during a refueling outage. On-line preventive maintenance provides the flexibility to focus more quality resources on any required or elective DG maintenance. For example, during refueling outages, resources are required to support many systems; during on-line maintenance, plant resources can be more focused on the DG preventative maintenance activities. The extended Completion Time associated with an inoperable DG will improve the effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities are associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. A longer Completion Time duration allows more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency.

2.4.2 Renewed Facility Operating License

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, “Additional Conditions,” by deleting the license conditions associated to Amendment No. 163. These license conditions were added to allow the use of a 7 day Completion Time for preplanned maintenance activities and relied on the availability of the Sharpe Station gensets. With the availability of the SBO DG System, the Sharpe Station availability is no longer required. As such, the license conditions associated with the Sharpe Station gensets are no longer necessary.

3.0 TECHNICAL EVALUATION

3.1 System Description

3.1.1 Offsite Power System

The WCGS offsite Alternating Current (AC) power supply for station startup, normal operation, and safe shutdown is supplied from the transmission network. Electrical power from the power grid to the plant site is supplied by two physically independent circuits designed and located to minimize the likelihood of simultaneous failure. Each of these independent circuits has the capability to safely shut down the unit. Each offsite power circuit is designed to be available in sufficient time to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded following a loss of all onsite power sources and the remaining offsite power circuit. Figure 1 (at the end of Attachment I) provides a one line diagram of the Offsite Power System and Onsite Power System.

One circuit supplies power to engineered safety features (ESF) transformer XNB01, which supplies power to its associated 4.16 kilovolt (kV) Class 1E bus and has the capacity to supply all “A” train safety related loads.

The other circuit is connected to the startup transformer and has the capacity to supply the startup loads and all auxiliary loads of the unit. The secondary winding of the startup transformer feeds ESF transformer XNB02, which supplies power to its associated 4.16 kV Class 1E bus and has the capacity to supply all “B” train safety related loads.

Each offsite power circuit can be manually aligned to supply power to the opposite or both 4.16 kV Class 1E busses, if required.

ESF transformers XNB01 and XNB02 are separated by a 3-hour fire wall. The cables associated with each of these offsite power circuits are routed in separate and distinct raceways.

The offsite power circuits, including the transformers and cables, are sized to carry their anticipated loads continuously. Each ESF transformer is sized to carry its associated safety related load group continuously. The secondary feeder cables to the 4.16 kV Class 1E busses are sized in excess of that required to carry their maximum load continuously. The startup transformer is sized to carry its anticipated load continuously but may be slightly overloaded under certain abnormal conditions.

The two offsite power circuits are fully testable. Since they are continuously energized, they are continuously tested by their use. When one circuit is shutdown, relays, meters, and other instruments can be tested and calibrated as required.

Instrumentation associated with the offsite AC power system provides sufficient information to determine the system availability at any time.

3.1.2 Onsite Power System

The Onsite Power System is provided with preferred power from the offsite system through two independent and redundant sources of power. One preferred circuit from the switchyard supplies power to ESF transformer XNB01 and the second offsite preferred circuit supplies power to the startup transformer which feeds two medium-voltage 13.8 kV busses and ESF transformer

XNB02. Each ESF transformer normally supplies its associated medium voltage 4.16 kV Class 1E bus. Figure 1 (at the end of Attachment I) provides a one line diagram of the Offsite Power System and Onsite Power System.

The two 13.8 kV busses supply power to the non-safety related auxiliary loads of the unit. The 13.8 kV busses are also connected to a three-winding unit auxiliary transformer, in addition to the startup transformer. The unit auxiliary transformer is connected to the main generator through an isolated phase bus duct.

Two 4.16 kV non-Class 1E busses are supplied power from two 13.8 kV busses through two 13.8/4.16 kV station service transformers. Non-Class 1E low-voltage 480 volt (V) loads are supplied power from two 13.8 kV busses through 480 V load centers and 480 V motor control centers.

The Onsite Power System is divided into two separate load groups, each load group consisting of an arrangement of busses, transformers, switching equipment, and loads fed from a common power supply. Power is supplied to auxiliaries at 13.8 kV, 4.16 kV, 480 V, 480/277 V, 208/120 V, 120 VAC, 250 VDC, and 125 VDC.

The onsite standby power source for each 4.16 kV Class 1E bus is a dedicated DG. DGs A and B are dedicated to 4.16 kV Class 1E buses NB01 and NB02, respectively. The standby power supply for each safety related load group consists of one DG complete with its accessories and fuel storage and transfer systems. It is capable of supplying essential loads necessary to reliably and safely shutdown and isolate the reactor. Each DG is rated at 6201 kW for continuous operation. Each DG is connected exclusively to a single 4.16 kV Class 1E bus for one load group. Each load group is adequate to satisfy minimum ESF demand caused by a LOCA and/or loss of preferred power supply. Class 1E AC system loads are separated into two load groups which are powered from separate ESF transformers or two independent DG (one per load group). Each load group distributes power by a 4.16 kV Class 1E bus, 480 V load centers, and 480 V motor control centers.

The DG starts automatically on a safety injection (SI) signal or on an ESF bus undervoltage signal. A degraded voltage signal produces an undervoltage condition by opening the normal and alternate feeder breakers to the bus(es) experiencing degraded voltage. Both signals are initiated from the load shedder and emergency load sequencer (LSELS). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a LSELS strips nonessential loads from the ESF bus. When the DG is tied to the ESF bus, essential loads are then sequentially connected to its respective ESF bus by the load sequencer.

The Class 1E DC System provides four separate 125 VDC battery supplies for Class 1E controls, instrumentation, power, and control inverters.

A SBO DG System is provided for improved nuclear plant safety resulting in MSPI/PRA margin. This system has the capacity to supply either train of safety related loads.

3.2 Grid Reliability

3.2.1 Generic Letter 2006-02, Grid Reliability and the Impact on Risk and the Operability of Offsite Power

The WCNOC response to Generic Letter (GL) 2006-002, “Grid Reliability and the Impact on Risk and the Operability of Offsite Power,” was provided on March 31, 2006 (Reference 6.4) and supplemented on January 31, 2007 (Reference 6.5). The NRC completed their review of GL 2006-02 as documented in their letter dated May 10, 2007 (Reference 6.6).

3.2.2 Recent Offsite Power System Reliability Improvements

Recent modifications included relocating the feed for the Startup transformer from the West bus to be between breakers 345-100 and 345-110. This has reduced the risk of a fault on the West bus taking out the Startup transformer, as it could still be fed from the Waverly/LaCygne line. The feed for the #7 transformer was relocated from the East bus to be between breakers 345-80 and 345-90. This has reduced the risk of a fault on the East bus taking out the #7 transformer, as it could still be fed from the Benton line.

The ESF transformers, XNB01 and XNB02, are being replaced with new transformers that have automatic load tap changers (LTCs) on the secondary side of the transformer (Reference 6.13). LTCs can provide acceptable operating voltages to the safety related electrical distribution system under a wider range of offsite power system voltages. ESF transformer XNB02 was replaced during Refueling Outage 24 (Spring 2021). Replacement of transformer XNB01 is planned for Refueling Outage 25.

3.3 Station Blackout Capability

Station Blackout (SBO) refers to a complete loss of all offsite and onsite AC power. The SBO rule (10 CFR 50.63) requires utilities to assess the impact of a loss of preferred power (i.e., offsite power) concurrent with a loss of the unit's standby DGs. The WCNOC SBO analysis has been performed in accordance with the guidelines provided in RG 1.155, “Station Blackout” (Reference 6.7), and Nuclear Utility Management and Resources Council (NUMARC) 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors” (Reference 6.8). The NRC's evaluation of WCGS’s compliance with the SBO rule is included in WCGS Supplemental Safety Evaluation dated June 16, 1992 (Reference 6.9).

WCGS is an AC-independent plant subject to a minimum SBO coping capability of four hours. The SBO coping duration for WCGS was calculated in accordance with the guidance provided in NUMARC 87-00.

Unique plant site parameters and plant design equipment characteristics for compliance with 10 CFR 50.63 are:

Power Design Characteristic Group (P):	P1
Extremely Severe Weather (ESW Group):	1
Severe Weather (SW Group):	2
Emergency AC Power Configuration (EAC):	C

Independence of Offsite Power (I Group):	I 1/2
DG Reliability Target:	0.95

WCNOC monitors the DG reliability under the Technical Requirement Manual, TR 5.5.2, “Emergency Diesel Generator Reliability Program,” and the Maintenance Rule Program. Increasing the DG Completion Time will not affect the DG reliability target used in the SBO coping assessment.

3.4 Supplemental AC Power (SBO DGs)

3.4.1 SBO DG System Description

The SBO DG System consists of a missile barrier located outside of the protected area that contains the necessary equipment required to provide reliable power to 4.16 kV Class 1E bus NB01 or NB02 during a station blackout event, and to a non-safety auxiliary feedwater pump (NSAFP). Busses NB01 and NB02 feed two redundant load groups that are each capable of safely shutting down the plant. Figure 2 (at the end of Attachment I) provides the plant site layout for WCGS. The SBO DG System includes three non-safety related Kohler 3250 kW DGs and one Power Equipment Center (PEC). Figure 3 (at the end of Attachment I) provides a one line diagram of the SBO DG System.

The missile barrier is constructed to provide protection from tornado winds and tornado generated missiles.

a. The foundation slab is designed for dead loads, live loads, tornado wind and missile loads, and seismic loads according to the International Building Code (IBC). The floor elevation is 2000’, which is above the probable maximum precipitation flooding elevation for the site. The slab thickness will resist overturning andfrost.

b. The missile barrier is constructed of five steel reinforced cast-in-place concrete walls running in the north-south direction and removable heavy duty steel grating acting as walls on the north and south ends.

   The two outermost (east and west) reinforced cast-in-place concrete walls are constructed to withstand tornado winds and tornado generated missiles. Reinforced cast-in-place concrete vestibules are constructed to protect the door entrances from tornado winds and tornado generated missiles. The outer doors are not missile or fire rated.

   The three innermost reinforced cast-in-place concrete walls are to divide the missile barrier into four bays – three for the SBO DGs and one for the PEC. These walls provide fire separation between the bays. The doors between the four missile barrier bays are 3-hour fire rated. UL 924 qualified photo-luminescent exit signs are installed near the doors within the missile barrier structure.

   Within each SBO DG bay, a partition wall constructed of dampers that are housed by a hollow structural section tube steel frame separates the intake and exhaust sides of the DGs.

c. The north and south ends of the missile barrier are constructed of removable heavy-duty steel grating panels to withstand tornado winds and tornado generated missiles. Each end of the missile barrier heavy duty grating consists of four panels, one for each bay. Metal decking is attached to the north end grating of each SBO DG bay to act as a wind barrier against wind from the north. The heavy duty grating and metal decking ensure proper airflow to the SBO DG enclosures for cooling. The heavy duty grating also limits the tornado wind speeds inside the missile barrier to less than or equal to 150 mph during a 230 mph tornado event.

d. The roof is constructed of removable pre-cast reinforced concrete panels except for the northernmost panel in each DG bay which is constructed of heavy duty grating.

Three SBO DG bays inside the missile barrier contains a DG enclosure which houses the equipment necessary to start and run the DGs, i.e., starting battery, jacket water system, radiator, turbochargers, intercoolers, fuel tank, engine/exciter controllers, etc. The provided fuel tanks have sufficient capacity to provide a minimum of 24 hours of run time at full load.

The PEC bay includes nine 4.16 kV switchgear sections, four control panels, and one 125 volt DC battery system in addition to other auxiliary equipment required for operation of the system. One control panel is also located in each of the ESF switchgear rooms to allow operation of the SBO DG System without the need for plant personnel to be present in the missile barrier.

Starting of the SBO DGs in accordance with plant procedures must be initiated by an operator, from any of the following locations:

a. Engine control panel located within the DG enclosure.

b. Local control panel located inside the PEC. The DGs can be started simultaneously through a Human-Machine Interface (HMI) touchscreen. They can also be started individually through the HMI touch screen or through control switches.

c. Remote control panels located inside the ESF Switchgear Room. The DGs can be started either individually or simultaneously through HMI touchscreens.

The Kohler-supplied switchgear is designed to control the three Kohler 3250 kW generators in parallel with each other. All transfers and tests are manually initiated using the HMI touchscreen.

There is one HMI touchscreen mounted on the control section in the PEC for system monitoring and control. The Kohler-provided PLC-based control system consists of one hot standby master PLC and a PLC for each generator. In the event of a complete PLC system failure, the operator can use the control switches on the KU100 Local Control Panel to synchronize the generators and manually connect them to bus PB005.

There are two remote control panel enclosures. One is located in the NB01 Switchgear room and the other in the NB02 Switchgear room. There is one HMI touchscreen mounted on each remote enclosure for system monitoring and control. The control switches on each remote control panel enclosure, with the exception of the emergency stop push buttons, are not functional in Minimum Requirements Mode. The breakers in Switchgear rooms NB01 and NB02 for powering a Class 1E 4.16 kV bus (NB01 or NB02) must be operated locally. No status (except open/closed status of NB00114 and NB00214) or control of these breakers is available.

To protect the cables going from the PB005 bus to the NB buses, monitoring, alarms and protective relaying are utilized. The loading on the cables will be monitored by the PLC, using an elapsed time counter to track the amount of time that the cables are loaded beyond a specified setpoint. The HMI touchscreen will also alarm when the cables are loaded beyond the same setpoint. The setpoint along with a time delay is configurable through the HMI touchscreen. Protective relaying is present at the PB005 bus that prevents cable overload damage while allowing the required loads to be powered without spurious tripping.

The SBO DGs are designed and capable of being started and connected in parallel to either Class 1E 4.16 kV bus within 10 minutes of the onset of a station blackout event.

3.4.2 SBO DG – AC System Analysis

Calculation XX-E-022, “SBO Diesel Generators – AC System Analysis,” analyzed the effect of adding three (3) SBO DGs. These three DGs are designed to start and connect in parallel to either safety related Class 1E bus NB01 or NB02, within 10 minutes of station blackout. Three DGs sufficiently power all LOOP loads. An engineering evaluation was performed utilizing the Electrical Transient Analysis Program (ETAP) to perform load flow, short circuit, and motor starting analyses for LOOP scenarios. Calculation XX-E-022 and the engineering evaluation determined that two SBO DGs can successfully start the minimum required safe shutdown loads with sufficient starting voltages provided the loads are manually started with at least 30 seconds provided between starts. The guidance for manually starting safe shutdown loads is included in plant operating procedures.

BTP 8-8 states, in part, “To support the one-hour time for making this power source available, plants must assess their ability to cope with loss of all AC power for one hour independent of an AAC power source.” As discussed in Section 3.3 above, a calculation in accordance with the guidance provided in NUMARC 87-00 demonstrated that WCNOC is a 4-hour coping plant. This calculation did not credit a supplemental AC power source.

3.4.3 <u>SBO DG Operation</u>

BTP 8-8 (Reference 6.3) states in part that “….for plants using AAC or supplemental power sources discussed above, the time to make the AAC or supplemental power source available, including accomplishing the cross-connection, should be approximately one hour to enable restoration of battery chargers and control reactor coolant system inventory.” To meet the “approximately one hour” criterion, WCNOC utilizes emergency operating procedure EMG C-0, “Loss of All AC Power,” that guides the control room operators through the appropriate steps to systematically cope with a total loss of AC power. Procedure EMG C-0 is entered from procedures EMG E-0, “Reactor Trip or Safety Injection,” and EMG ES-01, “Rediagnosis,” on the indication that all AC emergency busses are deenergized. Procedure EMG C-0 provides guidance from when a loss of all AC power condition is diagnosed until AC power is restored and control room operators selects the appropriate plant recovery procedures. Procedure EMC C-0 is structured to address the loss of all AC power as an initiating event while including actions to address possible coincident occurrences such as a loss of reactor coolant.

The objective of the recovery/restoration techniques incorporated into EMG C-0 is to mitigate deterioration of the Reactor Coolant System (RCS) conditions with AC emergency power lost, and to provide direction to operators to recover AC power from an available source.

The SBO DGs provide a quick, reliable and readily available source of AC power for the applicable emergency bus (NB01 or NB02) when EMG C-0 and associated procedures call for it. Procedure EMG C-0 requires several steps to be performed prior to attempting to restore AC power and those steps can be completed quickly. Upon recognition of a loss of all AC power, control room operators verify that the reactor is tripped (to ensure that decay heat is the only heat input into the RCS) and that the turbine generator is tripped (to prevent an uncontrolled cooldown of the RCS). These actions are performed immediately. In the event of a loss of all AC power, RCP shutdown seal will actuate on high seal cooling temperature to limit leakage from the RCP seal package. This minimizes the chances of a seal LOCA due to RCP seal failure and allows operators to control reactor coolant inventory and pressure. If a manual start of available emergency DG(s) for the available emergency buss(es) from the control room is unsuccessful, off normal procedure OFN KJ-032, “Local Emergency Diesel Startup,” is used to try and start an available emergency DG locally. Upon failure of all attempts at restoring power from an emergency DG, Step 10 of EMG C-0 directs the operators to attempt to restore AC power from any source (i.e., restoring an emergency DG or restoring offsite power) using procedure OFN NB-030, “Loss of AC Emergency Bus NB01 (NB02).” The required SBO DGs become one of the options in EMG C-0/OFN NB-030 for restoring AC power. If the required SBO DGs are the chosen source of AC power, Nuclear Station Operators are dispatched after performing 3 steps in OFN NB-030 to one of the NB switchgear rooms to perform either procedure SYS KU-121, “Energizing NB01 from Station Blackout Diesel Generators,” or SYS KU-122, “Energizing NB02 from Station Blackout Diesel Generators,” to energize one of the emergency busses.

During a previous training cycle (August 31, 2020 to October 5, 2020) procedure EMG C-0 was performed on the plant simulator. The procedure was timed through the performance of Step 11 (check if AC power has been restored) with five crews having an average time of 11 minutes. The time to perform the applicable steps in OFN NB-030 and perform either SYS KU-121 or SYS KU-122 was not specifically timed as part of the performance of procedure EMG C-0. A licensed operator performed a walkthrough of the applicable steps in procedure OFN NB-030 and SYS KU-121/122 and was completed in approximately 15 minutes. The walkthrough and the timed portion of EMG C-0 to step 11 determined that the required SBO DGs can be placed in service powering an emergency bus (NB01 or NB02) within the approximate one hour time frame specified in BTP 8-8.

Licensed operators and Nuclear Station Operators received training on the purpose and use of the SBO DG System prior to the system being placed in service. The task to monitor and operate the SBO DGs is currently covered in the Licensed Operator Requalification program every four years.

3.4.4 Availability

The SBO DGs are operated and maintained according to approved plant procedures. The SBO DGs are routinely monitored during Nuclear Station Operator rounds, with the monitoring criteria identified in procedure CKL ZL-009, “Site Readings Sheets.”

The proposed TS will require verification of required SBO DG availability within 1 hour of entry into TS 3.8.1, Condition B, for an inoperable DG. Following initial evaluation of the required SBO DGs availability, the proposed TS will require ongoing verification of availability on a once per 8 hour frequency. The marked up TS Bases include information to verify the required SBO DG availability as follows:

a. A start/loaded test has been performed within 30 days of entry into the extended Completion Time. This portion of the Required Action evaluation is performed one time and is met with an administrative verification of this prior to a planned removal of a DG from service or after an emergent DG outage; and

b. Fuel oil tank level for each required SBO DG is verified locally to be ≥ 24 hour supply (SBO Mission Time Minimum Fuel Satisfied Light); and

c. Supporting system parameters for starting and operating each required SBO DG are verified to be within required limits for functional availability (e.g., battery state of charge).

The SBO DG System is not used to extend the Completion Time for more than one inoperable DG at any one time.

3.4.5 Periodic Testing

The SBO DG System is periodically tested to ensure continued reliability of the system.

Procedure STN KU-010, "Station Blackout Diesel and Non-Safety AFW Pump Test," is performed monthly to demonstrate the functionality of the SBO DGs. This surveillance test starts two SBO DGs in conjunction with starting the non-safety auxiliary feedwater (AFW) pump for providing a load on the two SBO DGs. The third SBO DG is subsequently started and run unloaded. Procedure acceptance criteria is to run the SBO DGs for greater than 20 minutes loaded or unloaded. The procedure specifies a rotation for which two SBO DGs are to be started and loaded.

Procedure STN KU-001A, "SBO DG to NB01 Functional Test," and STN KU-001B, "SBO DG to NB02 Functional Test," is performed every 18 months on a staggered test basis to demonstrate functionality of the SBO DGs ability to energize the associated Class 1E 4.16 kV bus and carry essential loads for a SBO event. Procedure STN KU-001A was initially performed in April 2014 and verified that two SBO DGs were capable of carrying the essential loads on the Class 1E NB01 bus. Procedure STN KU-001B was initially performed in April 2015 and verified that two SBO DGs were capable of carrying the essential loads on the Class 1E NB02 bus. ETAP sensitivity runs were performed that provides reasonable assurance that two SBO DGs could power the Class 1E NB01 or NB02 safe shutdown loads, including providing adequate starting voltage to the 4kV and 460Vac loads. Since the initial performances of STN KU-001A and 001B, these procedures were revised to include all three SBO DGs when the tests are performed. The performances of STN KU-001A, STN KU-001B and STN KU-010 provide periodic testing that ensures the capability and reliability of the SBO DGs.

3.5 DG Reliability Program

Technical Requirements Manual, TR 5.5.2, "Emergency Diesel Generator Reliability Program," establishes the requirements and guidelines for DG reliability, availability, and monitoring. The program is implemented in procedure AP 23E-001, "Emergency Diesel Generator Reliability Program." The program establishes DG reliability performance goals (target reliability) based upon the station blackout coping assessment. Target reliability goal monitoring is accomplished through monitoring methods that are based upon those described in Appendix D to NUMARC 87-00. The program provides measures to ensure detailed failure analysis and cause investigation of DG failures is performed and effective corrective actions taken in response to failures. The program requires monitoring DG availability and performance parameters to ensure target

reliability is met or exceeded including determining and evaluating the DG reliability indicators for the last 20, 50, and 100 demands. DG target reliability for WCGS is 0.950.

3.6 Maintenance Rule Program

The WCGS Maintenance Rule program has established three performance criteria to monitor the DGs. The Maintenance Rule performance criteria for unavailability provides a control mechanism on the usage of the extended Completion Time. The DG unavailability goal is ≤ 296 hours per train per 18 months. Current data indicates the ‘A’ train DG unavailability is approximately 37% of the established criteria and the ‘B’ train DG is approximately 54%. The DG reliability criteria is no more than 2 functional failures in the most recent 25 demands on the diesel engine (monitored on a “per engine” basis). WCGS is meeting this established goal. The ‘A’ DG was conservatively placed in (a)(1) status on September 10, 2019 as a result of the failure of the DG due to issues with the maintenance strategy for the intercooler heat exchanger temperature control valve thermostatic actuating devices (commonly termed “power pills”). The DG condition monitoring criteria is that the DG is performing within the limits of the DG Reliability Program.

The SBO DGs are included in the WCGS Maintenance Rule program. The SBO DG reliability criteria is established as no more than 2 functional failures in an 18 month period, on a system level. The SBO DG condition monitoring criteria is established as less than or equal to 2 engine failures (per train) that do not impact the system function and less than four total SBO DG failures during the monitoring period. WCGS is meeting these established goals.

The Maintenance Rule requires an evaluation be performed when equipment covered by the Maintenance Rule does not meets its performance criteria. If the pre-established performance criteria are not achieved for the DGs, they are considered for 10 CFR 50.65(a)(1) actions. These actions require increased management attention and goal setting to restore their performance to acceptable level. The actual out of service time for the DGs is minimized to ensure that the performance criteria are met.

3.7 Risk Management/Work Control and Scheduling

The risk impact associated with performance of system/component maintenance, testing, and equipment outages is assessed in accordance with procedure AP 22C-003, “On-Line Nuclear Safety and Generation Risk Assessment.” An On-Line Nuclear Safety and Generation Risk Assessment is completed for the current weekly schedule. Compensatory measures, risk mitigating actions, and contingency plans are addressed for risk significant activities. The week scheduled activities and associated On-Line Nuclear Safety and Generation Risk Assessment are reviewed by the appropriate organizations with final approval and acceptance made by a management/supervisory member of the Operations Department whom possesses an active or current Senior Reactor Operator license. Maintenance and testing activities added to the weekly schedule (preplanned or emergent) are assessed for their impact upon the existing On-Line Nuclear Safety and Generation Risk Assessment.

On-line daily maintenance and testing activities are planned, scheduled and conducted in a manner to ensure both commercial and nuclear safety issues are assessed and the associated risks are managed. Risk assessment and management are accomplished by the following:

a. Ensuring systems, structures and components (SSCs) are maintained to support key functions necessary for safe shutdown, accident mitigation and commercial operation.

b. Planning and scheduling daily work activities in a manner that optimizes SSCs availability.

c. Developing compensatory measures to manage and minimize the operational risks associated with planned or emergent activities that are categorized as risk significant.

d. Not removing equipment from service for preventive or corrective maintenance activities unless there are reasonable expectations that equipment reliability can be improved and thus reduce the overall risk to safe operation of the facility.

e. Preplanning and sequencing maintenance activities to minimize repeated entries into TS LCO Conditions/Required Actions and to control system out of service time.

f. Maintaining a high degree of confidence that, prior to removing train related equipment from service, redundant equipment will remain available.

g. Wherever possible, on-line testing and maintenance of redundant equipment shall be avoided when the opposite components are out of service, particularly if the activities to be performed would increase the likelihood of a transient.

Experience has shown that, even with careful planning, maintenance duration sometimes approaches the Completion Time limit. In order to accommodate unanticipated problems, WCNOC has developed the practice of scheduling work for only 50 percent of the Completion Time for planned maintenance. Compared to the 72 hour Completion Time and pre-planned 7 day Completion Time (once per cycle per DG), the proposed 14 day Completion Time will reduce DG unavailability for the minor maintenance activities and maintenance activities currently performed under the 7 day Completion Time. Maintenance activities that can be performed within a Completion Time of 72 hours are not expected to change. By combining activities into fewer DG outages, based on the extended Completion Time, the DG availability is expected to improve, which would result in a net reduction in risk.

Procedures SYS KJ-200, “Inoperable Emergency Diesel,” and AP 21C-001, “Wolf Creek Substation,” provide the guidance for communications between the Transmission System Operator and control room operators on the status of the plant and the transmission system when a DG is taken out of service. Control room operators are responsible for the decision to proceed with activities which involve risk to plant systems. When it is intended to use the extended DG Completion Time, the TS Bases and procedure AP 22C-003 direct control room operators to ensure:

a. Weather conditions are conducive to an extended DG Completion Time.

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. Elective maintenance or testing that would challenge offsite power availability is that activity that could result in an electrical power distribution system (offsite circuit or transmission network) transient or make the offsite circuit(s) unavailable or inoperable. The operational risk assessment procedure provides a list of equipment that could challenge offsite power availability.

c. 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).

To meet the guidance in BTP 8-8, plant procedures will be revised to include daily communications between the Transmission System Operator and control room operators on the status of the plant and the transmission system when a DG is taken out of service.

3.8 Deterministic Assessment of Proposed DG Completion Time Extension

The impact of the proposed change would allow continued power operation up to an additional 11 days while DG maintenance or testing is performed. The DG is a standby electrical power source whose safety function is required when preferred power is unavailable and an event occurs that requires operation of the plant engineered safety features.

The onsite standby power source for each safety related load group consists of one dedicated DG complete with its accessories and fuel storage and transfer systems. The onsite standby power source provides adequate capacity and testability to supply the required engineered safety features and protection systems. The onsite standby power source is designed with adequate independency, redundancy, capacity and testability to ensure power is available for the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This onsite standby power source will successfully provide the required capacity when a failure of a single active component is assumed.

Each DG is connected exclusively to a single 4.16-kV engineered safety feature bus for one load group. The load groups are redundant and have similar safety related equipment. Each load group is adequate to satisfy minimum engineered safety features demand caused by a LOCA and/or loss of preferred power supply. Since the DGs can accommodate a single failure, extending the Completion Time for an inoperable DG has no impact on the system design basis. Safety analyses acceptance criteria, as provided in the Updated Safety Analysis Report (USAR), are not impacted by the proposed changes. AC power sources credited in the accident analyses will remain the same.

To ensure that the single failure design criterion is met, LCOs are specified in the TSs requiring all redundant components of the onsite power system to be operable. In the event that a DG is inoperable in MODES 1, 2, 3 and 4, existing TS 3.8.1 Required Action B.1 requires verification of the operability of the offsite circuits on a more frequent basis. When the required redundancy is not maintained, action is required within the specified Completion Time to initiate a plant shutdown. The Completion Time provides a limited time to restore equipment to operable status and represents a balance between the risk associated with continued operation without the required system or component redundancy and the risk associated with initiating a plant transient while transitioning the plant to a shutdown condition. Thus, the acceptability of the maximum length of the extended Completion Time interval relative to the potential occurrences of design basis events is considered. Since a proposed extension to the Completion Time for a single

inoperable DG does not change the design basis for the onsite standby power sources (i.e., DGs), the proposed change is acceptable and consistent with BTP 8-8.

The WCGS coping times during a SBO are not affected by the proposed change to extend the Completion Time for one inoperable DG. The coping times are calculated based on guidance provided in NUMARC 87-00 (Reference 6.8). The assumptions and the results of the SBO analyses are not changed by an extension of the Completion Time, and compliance with 10 CFR 50.63 will be maintained. In addition, DG reliability will be maintained at or above the SBO target level of 0.95, and the effectiveness of maintenance on the DGs and support systems will be monitored pursuant to the Maintenance Rule. The Maintenance Rule performance measure for unavailability also provides a control mechanism for the usage of the extended Completion Time.

Based on the above discussion, extending the Completion Time for a single inoperable DG from 72 hours to 14 days is acceptable because the plant's design basis will not be impacted. The 11 day extension of the Completion Time is consistent with BTP 8-8. The impact of an extended Completion Time is evaluated in a probabilistic framework in the discussion that follows (see Section 3.9).

To ensure that the risk associated with extending the Completion Time for an inoperable DG is minimized and consistent with the philosophy of maintaining defense-in-depth, compensatory measures will be applied. The required availability of the SBO DGs for the extended Completion Time for one inoperable DG is incorporated into the proposed TS changes. Other measures are provided in Attachment VIII, "List of Regulatory Commitments." These measures will ensure the risk associated with removing a DG from service is appropriately managed during the extended Completion Time for one inoperable DG.

Without approval of an extended Completion Time, scheduled DG maintenance and modifications could require an extended refueling outage so that a DG could be removed from service without any TS implications. Additionally, if an unplanned removal of a DG from service occurs and the DG is not restored to operable status within 72 hours, a plant shutdown would be required upon expiration of the 72 hour Completion Time provided in TS 3.8.1. Shutdown of the plant involves many plant operator activities and plant evolutions that challenge plant equipment, present opportunities for operator error and increase the possibility of a plant trip. It should also be noted that shutdown of the plant does not remove the desire to have a DG available to support its associated Class 1E bus. A plant that is shutdown still requires operation of the decay heat removal system, which is dependent on an operable Class 1E bus. Granting the requested license amendment and allowing continued steady state operation, additional operator activities and plant evolutions associated with a plant shutdown could be avoided. The increased possibility of a plant trip may also be avoided. The proposed change for an additional 11 days to the Completion Time for one inoperable DG is a reasonable amount of time for which a regulatory basis exists. The additional time by which the Completion Time would be extended is considered small. Due to the short time period, the probability of a design basis accident occurring during this interval is considered to be low.

3.9 Risk Assessment

A quantitative and qualitative analysis of risk was performed to support the conclusion that the change in risk associated with the proposed Completion Time extension for the DGs is acceptable. The detailed risk analysis is provided in Attachment II. The risk analysis addressed Key Principles 4 and 5 of RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.177,

"Plant-Specific, Risk-Informed Decision making: Technical Specifications," and the risk was calculated consistent with NRC guidance provided in these RGs.

Key Principle 4: Change in Risk is Consistent with the Safety Goal Policy Statement

The risk assessment performed for this change addresses the philosophy of risk-informed decision-making and a summary report of the risk assessment is provided in Section 5.0 of Attachment II. The results provided in the below table are within the acceptance guidelines listed in NRC RG 1.177 for a permanent TS Completion Time extension. As such, the change in risk is small and consistent with the intent of the Commission's Safety Goal Policy Statement. Section 3.0 of Attachment II provides a summary of the risk results in support of the proposed permanent TS change to extend the Completion Time from 72 hours to 14 days for either DG.

Key Principle 5: Monitor the Impact of the Proposed Change

The impact of the proposed change will be monitored for effectiveness in accordance with the existing plant maintenance rule program pursuant to 10 CFR 50.65(a)(4) and the associated implementation guidance, RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program requires, in part, that performing maintenance activities shall not reduce the overall availability of SSCs, which are important to safety.

ICCDP and ICLERP Results for DG Completion Time Extension from 72 hours to 14 Days (Sharpe Station Unavailable)

		Internal Events	**Internal Flood**	**Total[1]**
DG NE01				
	Base Case	6.68E-06	1.20E-05	1.87E-05[4]
CDF	**DG NE01 Out of Service**	8.80E-06	1.66E-05	2.54E-05
	ICCDP[2]	8.14E-08	1.77E-07	2.58E-07[5]
	Base Case	7.35E-08	5.24E-08	1.26E-07[6]
LERF	**DG NE01 Out of Service**	9.71E-08	7.46E-08	1.72E-07
	ICLERP[3]	9.06E-10	8.54E-10	1.76E-09[7]
DG NE02				
	Base Case	6.68E-06	1.20E-05	1.87E-05[4]
CDF	**DG NE02 Out of Service**	8.17E-06	1.69E-05	2.51E-05
	ICCDP[2]	5.71E-08	1.89E-07	2.47E-07[5]
	Base Case	7.35E-08	5.24E-08	1.26E-07[6]
LERF	**DG NE02 Out of Service**	8.93E-08	7.45E-08	1.64E-07
	ICLERP[3]	6.07E-10	8.50E-10	1.46E-09[7]

Notes:
(1) The contribution from Fire, High Winds, Seismic and Other External Hazards to baseline CDF / LERF values was evaluated qualitatively in Section 4.1
(2) The ICCDP values were calculated using the following equation:
ICCDP = (OOS case – Base case) * (14/365)
(3) The ICLERP values were calculated using the following equation:
ICLERP = (OOS case – Base case) *(14/365)
(4) Total CDF meets the RG 1.174 acceptance criteria of < 1E-4 per year
(5) Total ICCDP meets the RG 1.177 acceptance criteria of < 1E-6 per year
(6) Total LERF meets the RG 1.174 acceptance criteria of < 1E-5 per year
(7) Total ICLERP meets the RG 1.177 acceptance criteria of < 1E-7 per year

3.10 Traditional Engineering Considerations

For a SBO event during the proposed extended Completion Time, the required SBO DGs would be available to mitigate the event, and the plant would remain within the bounds of the accident analyses. In addition, there would be no adverse impact to the plant, because the TS 5.5.15, "Safety Function Determination Program (SFDP)," is utilized to ensure that cross-train checks are performed to ensure a loss of safety function does not go undetected. The SFDP will also ensure appropriate actions are taken if a loss of safety function is identified. Since the probability of a loss of safety function going undetected during a planned maintenance window is low, there is minimal safety impact due to the proposed extended Completion Time for an inoperable DG.

The combination of defense-in-depth and safety margin principles inherent in the onsite standby power sources ensures an emergency supply of power will be available to perform the required safety function. These elements of defense-in-depth and safety margin support a Completion Time extension to 14 days to allow a DG to be out of service for a longer period of time, as discussed further below.

3.10.1 Defense-in-Depth

The proposed change to the Completion Time for a DG out of service maintains system redundancy, independence and diversity commensurate with the expected challenges to system operation. The other DG, offsite sources of power and the associated engineered safety equipment will remain operable to mitigate the consequences of any previously analyzed accident. Otherwise, the SFDP will require that a loss of safety function be declared, and the appropriate TS Conditions and Required Actions taken. In addition to the SFDP, the Work Controls process provides for controls and assessments to preclude the possibility of simultaneous outages of redundant trains and to ensure system reliability. The Maintenance Rule performance measure for unavailability also provides a control mechanism on the usage of the extended Completion Time. The proposed increase in the Completion Time associated with an inoperable DG while the plant is in MODES 1, 2, 3 or 4, will not alter the assumptions relative to the causes or mitigation of an accident.

With a DG inoperable, a loss of function has not occurred. The remaining offsite power sources and DG are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure.

As defined by RG 1.174 (Reference 6.10), consistency with the defense-in-depth philosophy is maintained if the following occurs regarding the proposed licensing basis change:

a. Preserve a reasonable balance among the layers of defense.

   Installation of the supplemental power source (i.e., SBO DG System) ensures a reasonable balance is preserved between prevention of core damage, prevention of containment failure and consequence mitigation for the proposed extension to the current TS 3.8.1 Completion Time for one inoperable DG to 14 days. The proposed Completion Time extension will not significantly reduce the effectiveness of any of the following four layers of defense that exist in the plant design: minimizing challenges to the plant, preventing any events from progressing to core damage, containing the radioactive source term and emergency preparedness. Extending the Completion Time for one inoperable DG does not increase the likelihood of initiating events and does not create new initiating events. Furthermore, the proposed Completion Time extension does not significantly impact the availability and reliability of SSCs

that are relied upon to perform safety functions that prevent plant challenges from progressing to core damage. Lastly, the proposed change does not significantly impact the containment function or SSCs that support the containment function and also does not involve the emergency preparedness program or any of its functions.

b. Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.

As prescribed in BTP 8-8, a supplemental power source (i.e., the SBO DG System) is available as a backup to an inoperable DG to maintain the defense-in-depth design philosophy for the electrical power system to meet its intended safety function. The SBO DG System reduces the reliance on programmatic activities as compensatory measures associated with the proposed TS 3.8.1 Completion Time changes.

Plant safety systems are designed with redundancy so that when one train is inoperable, a redundant train can provide the necessary safety function. The preferred approach for accomplishing safety functions is through engineered systems, rather than overreliance on programmatic activities (i.e., compensatory measures). During the period when a DG is inoperable, an existing redundant source of power will be maintained operable. As previously highlighted, in the event other equipment becomes inoperable concurrent with the DG inoperability, the SFDP requires cross-division checks to ensure a loss of safety function does not go undetected. If a loss of safety function is identified, TS LCO 3.0.6 requires entry into the applicable Conditions and Required Actions for the system that possesses the loss of safety function.

c. Preserve system redundancy, independence, and diversity commensurate with the expected frequency, consequences of challenges to the system, including consideration of uncertainty.

The redundancy, independence and diversity of the onsite standby power sources will be maintained during the extended Completion Time. There were no identified uncertainties in redundancy, independence and diversity with the introduction of the SBO DG System or the extended Completion Time. The SBO DGs are not susceptible to the same common cause failures as the safety related DGs since the SBO DGs have a different manufacturer, operate at different speeds, have different starting systems, etc. Thus, the proposed change improves the independence and diversity of the onsite AC power sources.

d. Preserve adequate defense against potential common-cause failures (CCFs).

Defenses against common cause failures are preserved. New common cause failure mechanisms are not created as a result of the proposed changes to extend the Completion Time for one DG inoperable. The additional supplemental power source (i.e., SBO DG System) does not have any common linkage with the existing DGs beyond the potential for the same personnel that will be performing the maintenance. The operating environment and operating parameters for the safety related DGs remain constant; therefore, new common cause failure modes are not introduced. Redundant and backup systems are not impacted by the proposed changes and no new common cause links between the primary and backup systems are introduced.

e. Maintain multiple fission product barriers.

The barriers protecting the public and the independence of these barriers are maintained. Multiple DGs, systems and electrical distribution systems will not be removed from service simultaneously, as that could lead to degradation of the barriers and an increase in risk to the public. In the event other equipment becomes inoperable concurrent with DG inoperability, the SFDP requires cross-division checks to ensure a loss of safety function does not go undetected. If a loss of safety function is identified, TS LCO 3.0.6 requires entry into the applicable Conditions and Required Actions for the system that possesses the loss of safety function.

Furthermore, TS 3.8.1, existing Required Action B.2 (proposed Required Action B.3) requires declaring required feature(s) supported by the inoperable DG, inoperable when its redundant required feature(s) are inoperable. Existing Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These required features within the context of existing Required Action B.2 are designed to be powered from redundant safety related 4.16 kV emergency buses. Redundant required feature failures consist of inoperable features associated with an emergency bus redundant to the emergency bus associated with the inoperable DG.

In addition, the extended Completion Time does not provide a mechanism that degrades the independence of the barriers at WCGS; fuel cladding, reactor coolant system and containment.

f. Preserve sufficient defense against human errors.

The proposed extension to the Completion Time does not introduce any new operator actions for the onsite standby power sources (i.e., DGs). However, operators are required to operate and align the required SBO DGs. Licensed operators and Nuclear Station Operators are trained on the purpose and use of the SBO DG System and the associated procedural actions. Section 3.4.2 above discusses the actions taken by plant operators for operating the required SBO DGs.

g. Continue to meet the intent of the plant' design.

The design and operation of the onsite standby power sources (i.e., DGs) are not altered by the proposed Completion Time extension. The safety analyses safety criteria stated in the USAR is not impacted by the proposed changes. Redundancy and diversity of the DGs are not altered because the system design and operation are not changed by the proposed Completion Time extension. The proposed changes to the TSs will not allow plant operation in a configuration outside the plant's design basis. The requirements credited in the accident analyses regarding the DGs remain the same.

3.10.2 Safety Margin

When the plant is in MODES 1, 2, 3 or 4 and will operate periodically in the extended Completion Time for an inoperable DG, the plant remains in a condition for which it has already been analyzed; therefore, from a deterministic perspective, the proposed TS change is acceptable. The 14 day and 17 day Completion Times are deterministic based Completion Times supplemented with risk insights based on plant specific analyses using the methodology defined

in this license amendment request. The Maintenance Rule (i.e., 10 CFR 50.65) requires each licensee to monitor the performance or condition of the DGs to ensure that they are capable of performing their intended safety functions. If the performance or condition of the DGs do not meet performance criteria, appropriate corrective action is required along with goals to monitor effectiveness of the corrective action. Additionally, the Maintenance Rule performance measure for unavailability also provides a control mechanism for the usage of the extended Completion Time.

Furthermore, in order to support this TS change request, a supplemental AC power source (i.e., SBO DG System) is available with the capability to power any essential bus within approximately one hour from the from the loss of all AC power event. The required SBO DGs have the capacity to bring the plant to cold shutdown condition.

The evaluation that follows, using the principles defined in RG 1.174 (Reference 6.10), demonstrates that the proposed licensing bases changes are consistent with the principle that sufficient safety margins are maintained.

With sufficient safety margins, the following are true for WCGS:

(1) “the codes and standards or their alternatives approved for use by the NRC are met, and”

The design and operation of the DGs is not altered by the proposed Completion Time extension. Redundancy and diversity of the electrical distribution system will be maintained. The SBO DG System provides a supplemental AC power source as a defense-in-depth measure for a SBO event.

(2) “safety analysis acceptance criteria in the licensing basis (e.g., FSAR, supporting analyses) are met or proposed revisions provide sufficient margin to account for uncertainty in analysis and data.”

The safety analyses acceptance criteria stated in the USAR are not impacted by the proposed change. The proposed change will not allow plant operation in a configuration outside the design bases. The requirements regarding the DGs credited in the accident analyses will remain the same.

Given the above, WCNOC concludes that safety margins are not impacted by the proposed change.

3.11 Conclusion

The results of the deterministic assessment supplemented with risk insights described above provide assurance that the equipment required to safely shutdown the plant and mitigate the effects of a design basis accident will remain capable of performing their safety functions when a DG is removed from service in accordance with the proposed 14 day Completion Time.

The proposed Completion Time is consistent with NRC policy and will continue to provide protection for the health and safety of the public. The proposed changes meet the following principles:

a. The proposed change meets the current regulations.

b. The proposed change is consistent with the defense-in-depth philosophy.

c. The proposed change maintains sufficient safety margins.

d. The proposed change results in acceptable risk metrics provided above that are consistent with the criteria in RG 1.174 and RG 1.177.

Therefore, based on the above evaluations, WCNOC believes that the proposed change to the WCGS licensing basis is acceptable and operation in the proposed manner will not present undue risk to public health and safety or be inimical to the common defense and security.

4.0 REGULATORY ANALYSIS

4.1 Applicable Regulatory Requirements

The proposed change has been evaluated to determine whether the applicable regulations and requirements, noted below, continue to be met.

Section 182a of the Atomic Energy Act requires applicants for nuclear power plant operating licenses to include TSs as part of the license. The TSs ensures the operational capability of SSCs that are required to protect the health and safety of the public. The NRC's requirements related to the content of the TSs are contained in Section 50.36 of Title 10 of the *Code of Federal Regulations* (10 CFR 50.36) which requires that the TSs include items in the following specific categories: (1) safety limits, limiting safety systems settings, and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements per 10 CFR 50.36(c)(3); (4) design features; and (5) administrative controls. The proposed change does not affect WCGS's compliance with the intent of 10 CFR 50.36.

10 CFR 50.63(a), "Loss of all alternating current power," requires that each light-water cooled nuclear power plant licensed to operate be able to withstand for a specified duration and recover from a station blackout. The proposed change does not affect WCGS's compliance with the intent of 10 CFR 50.63(a).

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires that preventive maintenance activities must not reduce the overall availability of the SSCs. It also requires that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The proposed change does not affect WCGS's compliance with the intent of 10 CFR 50.65.

10 CFR 50, Appendix A, General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR 50 states, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of SSCs that are important to safety. The onsite system is required to have sufficient independence, redundancy and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are 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. The proposed change does not affect WCGS's compliance with the intent of GDC 17.

10 CFR 50, Appendix A, GDC 18, “Inspection and testing of electric power systems,” states that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing of important areas and features, such as insulation and connections to assess the continuity of the systems and the condition of their components. The proposed change does not affect WCGS’s compliance with the intent of GDC 18.

4.2 Precedent

The NRC has previously approved changes similar to the proposed change in this license amendment request for other nuclear power plants including:

1. Brunswick Steam Electric Plant: Application dated June 19, 2012 (ADAMS Accession No. ML12173A112); NRC Safety Evaluation dated February 24, 2014 (ADAMS Accession No. ML13329A362).

   Similar to Brunswick, WCNOC chose to request a TS 3.8.1 Completion Time extension to 14 days for an inoperable DG. In the Brunswick application, Progress Energy proposed a modification to install a supplemental AC power source (SUPP-DG). The SBO DG System at WCGS is a currently installed and functional supplemental AC power source.

2. Catawba Nuclear Station and McGuire Nuclear Station: Application dated May 2, 2017 (ADAMS Accession No. ML17122A116); NRC Safety Evaluation dated August 27, 2019 (ADAMS Accession No. ML19212A655)

   Similar to Catawba and McGuire, WCNOC chose to request a TS 3.8.1 Completion Time extension to 14 days for an inoperable DG. In the Catawba and McGuire application, Duke Energy proposed a modification to install a supplemental AC power source (Emergency Supplemental Power Source (ESPS)). The SBO DG System at WCGS is a currently installed and functional supplemental AC power source. Additionally, Duke Energy proposed to add a new TS 3.8.1 Required Action for Condition B to ensure that at least one train of shared components has an operable emergency power supply. WCNOC is not proposing a similar change as WCGS is a single unit site.

WCNOC is proposing TS changes that are slightly different than those approved by the NRC in the above cited precedent. However, the proposed changes provide the same result as those approved above. The WCNOC proposed changes are consistent with the existing WCGS TSs and ensure consistency with TS Section 1.3, “Completion Times.” Additionally, the TS changes proposed by WCNOC are similar to the changes approved in Amendment Nos. 291 and 273 on September 30, 2005 for the Donald C. Cook Nuclear Plant, Units 1 and 2 (ADAMS Accession No. ML052720032).

4.3 No Significant Hazards Consideration Determination

The proposed amendment revises Wolf Creek Generating Station (WCGS) Technical Specification (TS) 3.8.1, “AC Sources –Operating,” by removing the requirements associated with the Sharpe Station gensets and extending the Completion Time in existing Required Action B.4.1 (proposed Required Action B.5) for one inoperable diesel generator (DG) from 72 hours to 14 days based upon the availability of a supplemental power source (i.e., Station Blackout (SBO) DG System). The proposed changes will provide operational and maintenance flexibility. The proposed changes will provide sufficient time to perform planned and emergent maintenance activities that cannot be performed within a 72 hour Completion Time.

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, “Additional Conditions,” by deleting the license conditions associated to Amendment No. 163. Amendment No. 163 revised WCGS TS 3.8.1, “AC Sources –Operating,” by adding requirements associated with the Sharpe Station gensets in Required Action B.4.1. With the use of the required SBO DGs, reliance on the Sharpe Station is no longer necessary.

Wolf Creek Nuclear Operating Corporation (WCNOC) has evaluated whether or not a significant hazards consideration is involved with the proposed changes by focusing on the three standards set forth in 10 CFR 50.92, “Issuance of amendment,” as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

   The proposed change involves extending the TS Completion Time for an inoperable DG. The DGs are safety related components which provide a backup electrical power supply to the Onsite Power System. The proposed change does not affect the design of the DGs, the operational characteristics or function of the DGs, the interfaces between the DGs and other plant systems or the reliability of the DGs. The DGs are not accident initiators; the DGs are designed to mitigate the consequences of previously evaluated accidents including a loss of offsite power. Extending the Completion Time for a single inoperable DG would not affect the previously evaluated accidents since the remaining DG supporting the redundant engineered safety feature systems would continue to be available to perform the accident mitigation functions. Thus, allowing a DG to be inoperable for an additional 11 days for performance of maintenance or testing does not increase the probability of a previously evaluated accident.

   Deterministic and probabilistic risk assessment techniques evaluated the effect of the proposed TS change to extend the Completion Time for an inoperable DG on the availability of an electrical power supply to the Engineered Safety Features Systems. These assessments concluded that the proposed TS change does not involve a significant increase in the risk of power supply unavailability.

   The risk assessment performed for this change addresses the philosophy of risk-informed decision-making. The results are within the acceptance guidelines listed in NRC Regulatory Guide 1.177, “Plant-Specific, Risk-Informed Decision making: Technical Specifications,” for a permanent TS Completion Time extension. As such, the change in risk is small and consistent with the intent of the Commission's Safety Goal Policy Statement.

   The remaining operable DG is adequate to supply electrical power to a single 4.16 kV Class 1E bus. A DG is required to operate only if both offsite power sources fail and there is an event which requires operation of the plant engineered safety features such as a design basis accident. The probability of a design basis accident occurring during the extended Completion Time is low.

   The consequences of previously evaluated accidents will remain the same during the proposed 14 day Completion Time as during the current 72 hour Completion Time. The ability of the remaining TS required DGs to mitigate the consequences of an accident will

not be affected since no additional failures are postulated while equipment is inoperable within the TS Completion Time.

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, “Additional Conditions,” by deleting the license conditions associated to Amendment No. 163. The deletion of the license conditions does not increase the probability of a previously evaluated accident.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

The proposed change involves extending the TS Completion Time for an inoperable DG. The proposed change does not involve a change in the plant design, plant configuration or system operation of the DGs. The proposed change allows a DG to be inoperable for additional time. Equipment will be operated in the same configuration and manner that is currently allowed and designed for. The functional demands on credited equipment is unchanged. There are no new failure modes or mechanisms created due to plant operation for an extended period to perform DG maintenance or testing. Extended operation with an inoperable DG does not involve any modification to the operational limits or physical design of plant systems. There are no new accident precursors generated due to the extended Completion Time.

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, “Additional Conditions,” by deleting the license conditions associated to Amendment No. 163. The deletion of the license conditions does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Therefore, the proposed change will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No

The proposed change involves extending the TS Completion Time for an inoperable DG. Currently, if an inoperable DG is not restored to operable status within 72 hours, TS 3.8.1, requires the plant to be in MODE 3 (i.e., Hot Standby) within a Completion Time of 6 hours, and to be in MODE 5 (i.e., Cold Shutdown) within a Completion Time of 36 hours. The proposed TS change will allow steady state plant operation at 100 percent power for an additional 11 days for performance of DG planned reliability improvements and preventive and corrective maintenance.

Deterministic and probabilistic risk assessment techniques evaluated the effect of the proposed TS change to extend the Completion Time for an inoperable DG on the availability of an electrical power supply to the Engineered Safety Features Systems.

These assessments concluded that the proposed TS change does not involve a significant increase in the risk of power supply unavailability.

The DGs continue to meet their design requirements; there is no reduction in capability or change in design configuration. The DG response to loss of offsite power, loss of coolant accident, station blackout or fire scenarios is not changed by this proposed amendment; there is no change to the DG operating parameters. In the extended Completion Time, as in the existing Completion Time, the remaining operable DG is adequate to supply electrical power to a single 4.16 kV Class 1E bus. The proposed change to extend the Completion Time for an inoperable DG does not alter a design basis safety limit; therefore, it does not significantly reduce the margin of safety. The DGs will continue to operate per the existing design and regulatory requirements.

The proposed amendment revises Renewed Facility Operating License No. NPF-42, Appendix D, “Additional Conditions,” by deleting the license conditions associated to Amendment No. 163. The deletion of the license conditions does not involve a significant reduction in a margin of safety.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based upon the reasoning presented above, WCNOC concludes that the requested change does not involve a significant hazards consideration as set forth in 10 CFR 50.92(c), “Issuance of amendment.”

4.4 Conclusion

Based on the considerations discussed herein, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

The proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20. However, the proposed change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amount of effluent that may be released offsite, or (iii) a significant increase in the individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environment impact statement environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

6.1 WCNOC letter WO 03-0057, “Revision to Technical Specifications – Extensions of AC Electrical Power Distribution Completions Times,” October 30, 2003. ADAMS Accession No. ML033110564).

6.2 Letter from J. N. Donohew, USNRC, to R. A. Muench, WCNOC, "Wolf Creek Generating Station – Issuance of Amendment RE: Extended Diesel Generator Completion Times (TAC NO. MC1257)," April 26, 2006. ADAMS Accession No. ML053490174.

6.3 Branch Technical Position (BTP) 8-8, "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions," Initial – February 2012. ADAMS Accession No. ML113640138.

6.4 WCNOC letter WM 06-0011, "60-Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," March 31, 2006.

6.5 WCNOC letter ET 07-0003, "Response to NRC Request for Additional Information Regarding NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," January 31, 2007. ADAMS Accession No. ML070380281.

6.6 Letter from J. N. Donohew, USNRC, to R. A. Muench, WCNOC, "Wolf Creek Generating Station – Closeout Letter for Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power" (TAC NO. MD1050)," May 10, 2007. ADAMS Accession No. ML071160422.

6.7 Regulatory Guide 1.155, "Station Blackout," August 1988. ADAMS Accession No. ML003740034.

6.8 Nuclear Utility Management and Resources Council (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," November 1987.

6.9 Letter from W. D. Reckley, USNRC, to B. D. Withers, WCNOC, "Wolf Creek Generating Station – Supplemental Safety Evaluation Regarding the Station Blackout Rule (10 CFR 50.63) (TAC NO M68626)," June 16, 1992.

6.10 RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases," Revision 3, January 2018.

6.11 RG 1.177, "Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 2, January 2021.

6.12 WCNOC letter WO 11-0006, "Licensee Event Report 2010-014-00, "Technical Specification Required Shutdown Due to Inadequate Planning Resulting in Extended Emergency Diesel Generator Inoperability"," February 4, 2011. ADAMS Accession No. ML110460684.

6.13 WCNOC letter ET 20-0007, "License Amendment Request for Replacement of Engineered Safety Features Transformers with New Transformers that have Active Automatic Load Tap Changers," June 8, 2020. ADAMS Accession No. ML20160A458.

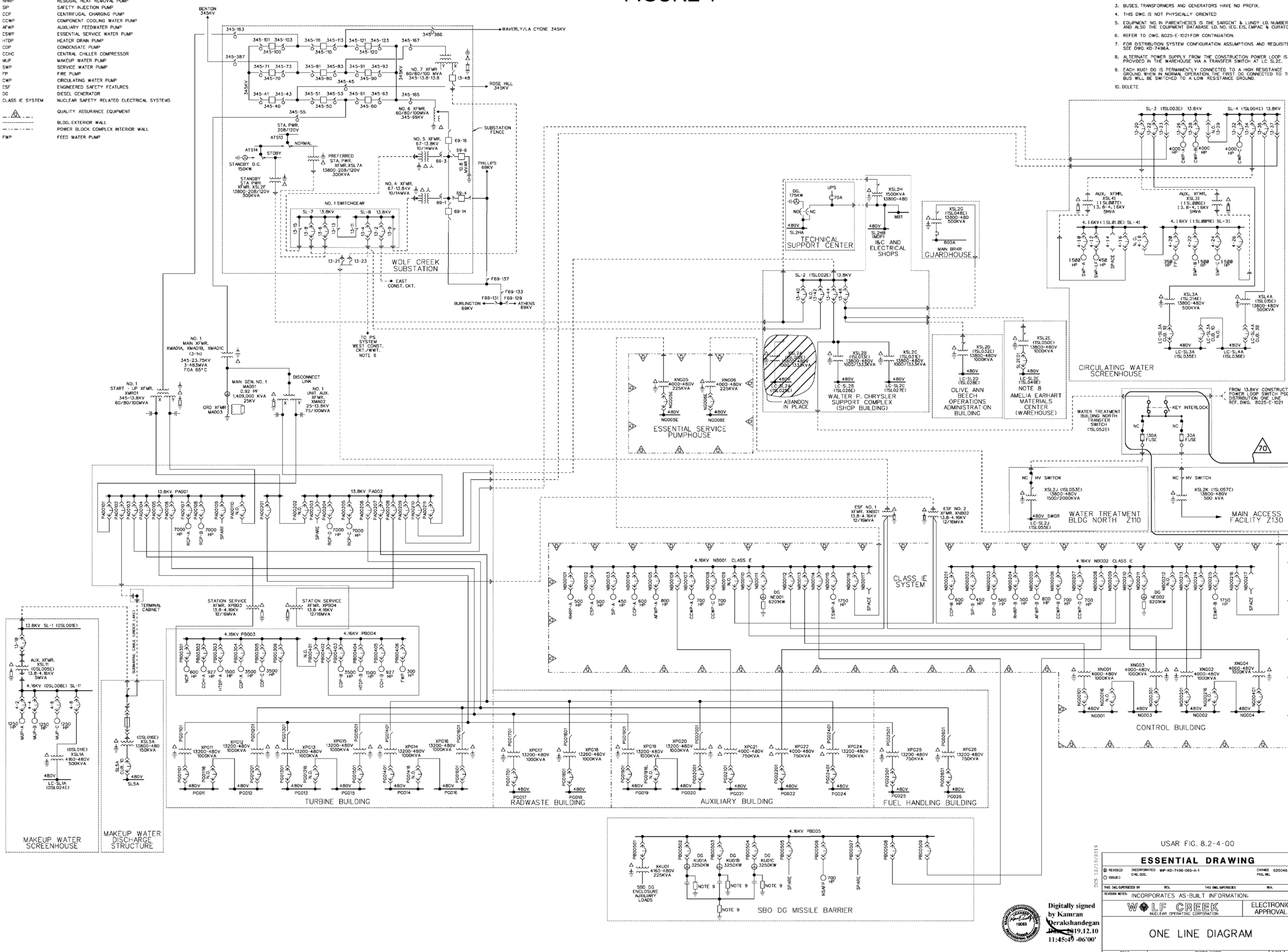
FIGURE 1

LEGEND

CSP	CONTAINMENT SPRAY PUMP
RCP	REACTOR COOLANT PUMP
RHRP	RESIDUAL HEAT REMOVAL PUMP
SIP	SAFETY INJECTION PUMP
CCP	CENTRIFUGAL CHARGING PUMP
CCWP	COMPONENT COOLING WATER PUMP
AFWP	AUXILIARY FEEDWATER PUMP
ESWP	ESSENTIAL SERVICE WATER PUMP
HTDP	HEATER DRAIN PUMP
CDP	CONDENSATE PUMP
CCHC	CENTRAL CHILLER COMPRESSOR
MUP	MAKEUP WATER PUMP
SWP	SERVICE WATER PUMP
FP	FIRE PUMP
CWP	CIRCULATING WATER PUMP
ESF	ENGINEERED SAFETY FEATURES
DG	DIESEL GENERATOR
CLASS IE SYSTEM	NUCLEAR SAFETY RELATED ELECTRICAL SYSTEMS
Q	QUALITY ASSURANCE EQUIPMENT
	BLDG. EXTERIOR WALL
	POWER BLOCK COMPLEX INTERIOR WALL
FWP	FEED WATER PUMP

NOTES:

1. THIS DRAWING IS FOR PLANNING PURPOSES ONLY. SEE SYSTEM OPERATION ONE - LINE DIAGRAM AND ELECTRICAL DRAWINGS FOR SWITCHING INFORMATION AND DETAILS.
2. DELETE
3. BUSES, TRANSFORMERS AND GENERATORS HAVE NO PREFIX.
4. THIS DWG. IS NOT PHYSICALLY ORIENTED
5. EQUIPMENT NO. IN PARENTHESES IS THE SARGENT & LUNDY I.D. NUMBER AND ALSO THE EQUIPMENT DATABASE I.D. NO. (EG. EIS, EMPAC & CURATOR).
6. REFER TO DWG. 8025-E-1021 FOR CONTINUATION.
7. FOR DISTRIBUTION SYSTEM CONFIGURATION ASSUMPTIONS AND REQUISITES SEE DWG. KD-7496A.
8. ALTERNATE POWER SUPPLY FROM THE CONSTRUCTION POWER LOOP IS PROVIDED IN THE WAREHOUSE VIA A TRANSFER SWITCH AT LC SL2E.
9. EACH KU01 DG IS PERMANENTLY CONNECTED TO A HIGH RESISTANCE GROUND. WHEN IN NORMAL OPERATION, THE FIRST DG CONNECTED TO THE BUS WILL BE SWITCHED TO A LOW RESISTANCE GROUND.
10. DELETE



USAR FIG. 8.2-4-00

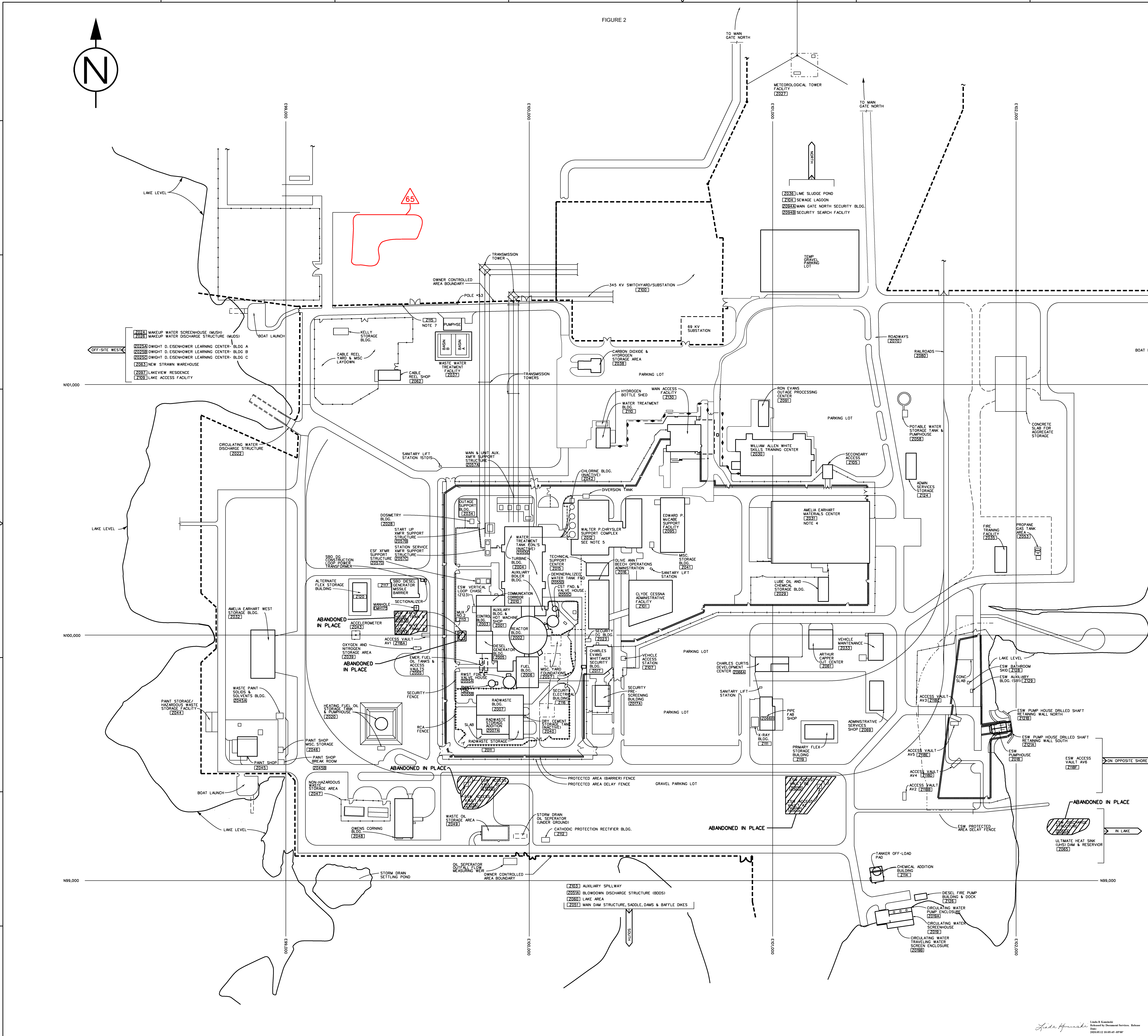
DCS 12/10/2019

Digitally signed by Kamran Derakshandegan Date: 2019.12.10 11:45:49 -06'00'

ESSENTIAL DRAWING		
⊗ REVISED ○ ISSUED	INCORPORATED CHG. DOC. WIP-KD-7496-066-A-1	CHANGE PKG. NO. 020046
THIS DWG. SUPERSEDED BY REV.	THIS DWG. SUPERSEDES REV.	
REVISION NOTES: INCORPORATES AS-BUILT INFORMATION;		
WOLF CREEK NUCLEAR OPERATING CORPORATION	ELECTRONIC APPROVAL	
ONE LINE DIAGRAM		
SCALE NONE	DRAWING NUMBER KD-7496	SHEET 1 REV 70

34X44 E SIZE

FIGURE 2



ALL CHANGES TO OR ADDITIONS OF BUILDING/STRUCTURE NAMES OR NUMBERS MUST BE COORDINATED WITH ENGINEERING AND REFLECTED ON THIS DRAWING.

NOTES:

1. FOR GENERAL NOTES SEE DWG. 8025-C-KG1201.
2. CHANGES TO THIS DWG. MAY AFFECT DWG. HA-CQ017, SHT. 1.
3. FOR GENERAL LOCATION OF BLDGS. OFF-SITE, SEE 8025-C-KG1201.
4. DRAWINGS FOR THE AMELIA EARHART MATERIALS CENTER ARE PRE-FIXED WITH Z031 AND Z031A (EXAMPLE: Z031-M-005).
5. DRAWINGS FOR THE WALTER P. CHRYSLER SUPPORT COMPLEX ARE PRE-FIXED WITH Z012A (SHOP BLDG), Z012B (TOOL ROOM) AND Z012C (I&C/ELEC. MAINT SHOP).
6. TANK FOUNDATION/VALVE HOUSE NUMBERS DO NOT INCLUDE THE TANK.
7. STRUCTURE Z115 IS THE ABOVE GROUND PORTION OF THE 13.8KV SITE POWER LOOP (ALSO KNOWN AS THE "CONSTRUCTION" POWER LOOP). COMPONENT DESIGNATOR Z115 INCLUDES ALL POLES, LINES AND ELECTRICAL DEVICES.
8. TEMPORARY TRAILERS, STORAGE BUILDING, LAYDOWN AREAS, AND PARKING, ADDED TO SUPPORT OUTAGE, ESW PIPING REPLACEMENT AND VARIOUS CONSTRUCTION PROJECTS.
9. DELETED.

LEGEND:

xxxxxxxx	PROTECTED AREA (BARRIER) FENCE
	RCA FENCE
——x——	PROTECTED AREA DELAY FENCE
-S-S-S-S-S-S-	SECURITY FENCE
-RS-RS-RS-RS-RS-	SECURITY FENCE AND RCA FENCE
— - - — - - -	VEHICLE BARRIER SYSTEM (SEE HC-CQ013, SHT. 1)
— ◆ — ◆	ORNAMENTAL IRON FENCE
▬ — ▬ —	YODOCK BARRIER

USAR FIG. 1.2-44

ESSENTIAL DRAWING

⊗ REVISED INCORPORATED CHG. DOC. CR# 00142117 CHANGE PKG. NO.
○ ISSUED

THIS DWG. SUPERSEDED BY REV. THIS DWG. SUPERSEDES REV.

REVISION NOTES: DELETE BUILDING Z056.

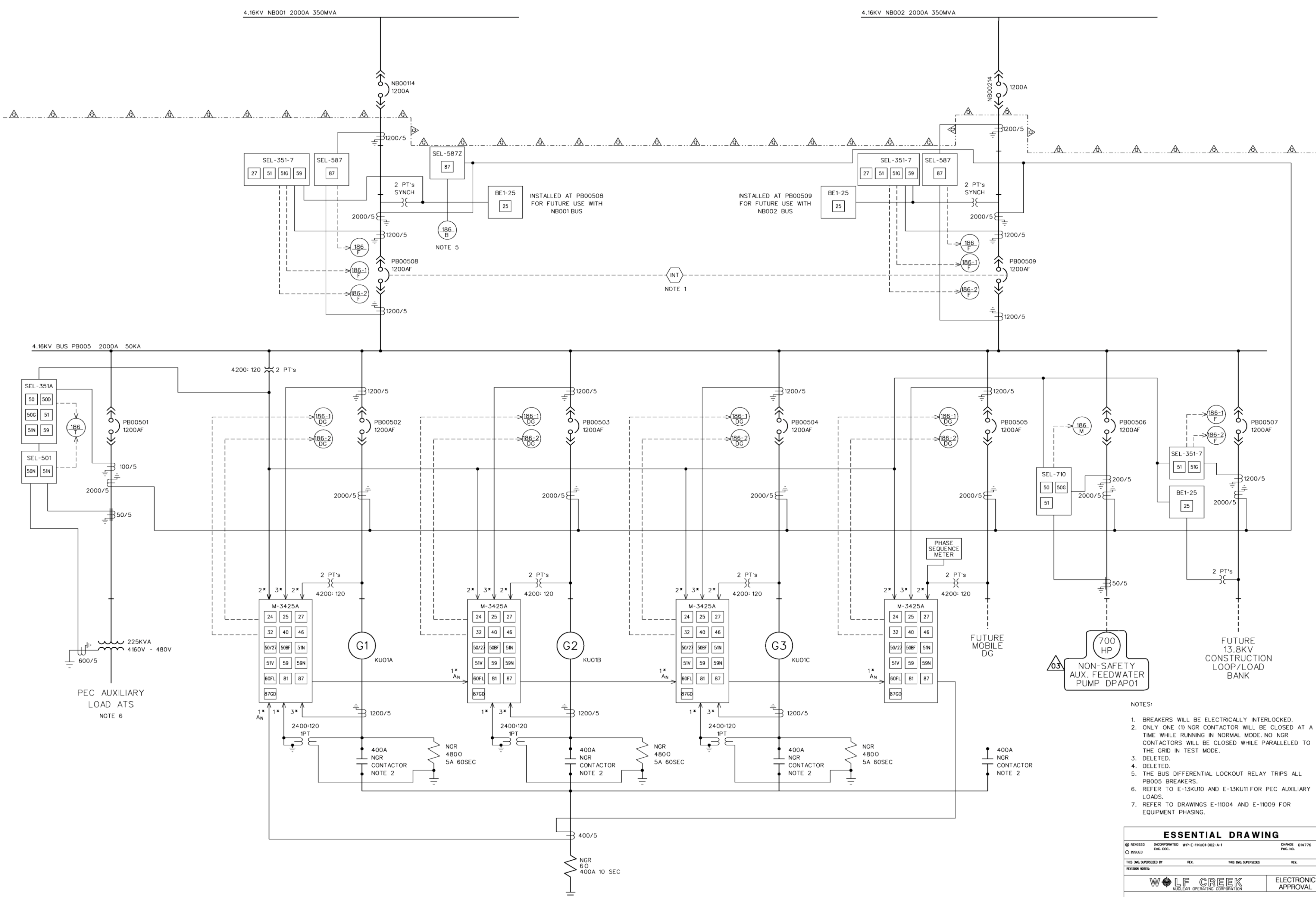
WOLF CREEK NUCLEAR OPERATING CORPORATION — ELECTRONIC APPROVAL

SITE PLAN

SCALE	DRAWING NUMBER	SHEET	REV
1"=132'-0"	8025-C-KG1202		65

34X44 E SIZE

FIGURE 3



NOTES:

1. BREAKERS WILL BE ELECTRICALLY INTERLOCKED.
2. ONLY ONE (1) NGR CONTACTOR WILL BE CLOSED AT A TIME WHILE RUNNING IN NORMAL MODE. NO NGR CONTACTORS WILL BE CLOSED WHILE PARALLELED TO THE GRID IN TEST MODE.
3. DELETED.
4. DELETED.
5. THE BUS DIFFERENTIAL LOCKOUT RELAY TRIPS ALL PB005 BREAKERS.
6. REFER TO E-13KU10 AND E-13KU11 FOR PEC AUXILIARY LOADS.
7. REFER TO DRAWINGS E-11004 AND E-11009 FOR EQUIPMENT PHASING.

ESSENTIAL DRAWING	
REVISED / ISSUED — INCORPORATED CHG. DOC. WIP-E-11KU01-002-A-1	CHANGE 014776 PKG. NO.
WOLF CREEK NUCLEAR OPERATING CORPORATION	ELECTRONIC APPROVAL
SBO DG ONE LINE DIAGRAM	
SCALE NONE	DRAWING NUMBER E-11KU01 — SHEET 1 — REV 03

34X44 E SIZE

ATTACHMENT II

RISK ASSESSMENT TO SUPPORT DIESEL GENERATOR COMPLETION TIME EXTENSION

Risk Assessment to Support Diesel Generator Completion Time Extension

Risk Assessment to Support Diesel Generator Completion Time Extension

A quantitative and qualitative analysis of risk was performed to support the conclusion that the change in risk associated with the proposed Technical Specification (TS) Completion Time extension for either Diesel Generator (DG, NE01 or NE02) is acceptable. The risk analysis addressed Key Principles 4 and 5 of Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.174 (Reference 1) and RG 1.177 (Reference 2) and the risk was calculated consistent with NRC guidance provided in these RGs.

Key Principle 4: Change in Risk is Consistent with the Safety Goal Policy Statement

The risk assessment performed for this change addresses the philosophy of risk-informed decision-making and a summary report of the risk assessment is provided in Section 5.0. The results are within the acceptance guidelines listed in NRC RG 1.177 (Reference 2) for a permanent TS Completion Time extension. As such, the change in risk is small and consistent with the intent of the Commission's Safety Goal Policy Statement. Section 3.0 of this Attachment provides a summary of the risk results in support of the proposed permanent TS change to extend the Completion Time from 72 hours to 14 days for either DG.

Key Principle 5: Monitor the Impact of the Proposed Change

The impact of the proposed change will be monitored for effectiveness in accordance with the existing plant maintenance rule program pursuant to 10 CFR 50.65(a)(4) and the associated implementation guidance, NRC RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (Reference 3). The program requires, in part, that performing maintenance activities shall not reduce the overall availability of structures, systems, and components (SSCs), which are important to safety.

1.0 PROBABILISTIC RISK ASSESSMENT CAPABILITY AND INSIGHTS

The risk assessment of the proposed Completion Time extension is based on quantitative models for Internal Events and Internal Flooding and qualitative assessments for Internal Fire and external hazards. The Wolf Creek Generating Station (WCGS) Internal Events and Internal Flooding models meet the scope and quality requirements of RG 1.200, Revision 2 "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" (Reference 4). Note that since the Internal Fire model is still in progress and has not been peer reviewed a qualitative evaluation is provided to support this application. Wolf Creek Nuclear Operating Corporation (WCNOC) guidance documents are in place for controlling and updating the models, when appropriate, and for assuring that the models represent the as-built, as-operated plant. The conclusion, therefore, is that the WCGS probabilistic risk assessment (PRA) models are acceptable for use in providing risk assessments for applications, including assessment of proposed TS amendments.

1.1 FLEX Equipment

The FLEX DGs are not credited as compensatory actions in the risk analysis for the extended DG Completion Time. The FLEX DG is further defense-in-depth available for extended loss of AC power (ELAP) scenarios in addition to the Station Blackout (SBO) DG System.

2.0 DEVELOPMENT AND USE OF PRA INSIGHTS

The evaluation for the proposed Completion Time extension consisted of a review of the impacted plant systems and their safety functions. There are no SSCs that will change status due to the proposed change. No new accidents or transients will be introduced by the proposed change. No physical changes are being made to any of the systems affected by the Completion Time extension. The function and operation of these systems will remain the same, as described in the plant design basis. Protective measures will be taken to ensure that unanticipated compromises to system redundancy, independence, and diversity will not occur during maintenance activities.

3.0 RISK ASSESSMENT RESULTS

The table provided herein documents the results of the PRA conducted in support of the proposed permanent TS change to extend the restoration Completion Time from 72 hours to 14 days for each DG. Details of the risk assessment are provided in Section 5.0 to this Attachment. Because the proposed change is a permanent change, the following acceptance guidelines from NRC RG 1.177 (Reference 2) are applicable for evaluating the core damage frequency (CDF) and large early release frequency (LERF) risk associated with allowed outage time (AOT) changes:

- An Incremental conditional core damage probability (ICCDP) of less than 1.0E-06 and incremental conditional large early release probability (ICLERP) of less than 1.0E-07

The ICCDP and ICLERP risk quantification results, presented in Table 1, are based on a DG restoration Completion Time of 14 days. The base case results reflect the average AOT due to test and maintenance. Cases were run for both DGs and all results are presented below. NE01 out of service (OOS) was found to be limiting. This asymmetry is driven by the WCGS design where the turbine-driven auxiliary feedwater pump (TDAFWP) receives DC control power from the Train B Cass 1E bus (NB02). Without the Class 1E bus the TDAFWP will fail after battery depletion. Therefore, in the Train B alignment when NE01 is OOS a loss of the operating NB bus (NB02 in this case) will cause a failure of the operating Component Cooling Water (CCW) Train as well as power to the TDAFWP for mitigation; whereas the Train A alignment would only result in loss of the operating CCW Train, with no impact to the TDAFWP.

Table 1: ICCDP and ICLERP Results for DG Completion Time Extension from 72 hours to 14 Days (Sharpe Station Available)

		Internal Events	**Internal Flood**	**Total[1]**
DG NE01				
CDF	**Base Case**	6.68E-06	1.20E-05	1.87E-05[4]
	DG Out of Service	8.76E-06	1.66E-05	2.54E-05
	ICCDP[2]	7.97E-08	1.77E-07	2.57E-07[5]
LERF	**Base Case**	7.35E-08	5.24E-08	1.26E-07[6]
	DG Out of Service	9.69E-08	7.46E-08	1.72E-07
	ICLERP[3]	8.97E-10	8.54E-10	1.75E-09[7]
DG NE02				
CDF	**Base Case**	6.68E-06	1.20E-05	1.87E-05[4]
	DG Out of Service	8.12E-06	1.69E-05	2.50E-05
	ICCDP[2]	5.54E-08	1.89E-07	2.45E-07[5]
LERF	**Base Case**	7.35E-08	5.24E-08	1.26E-07[6]

Table 1: ICCDP and ICLERP Results for DG Completion Time Extension from 72 hours to 14 Days (Sharpe Station Available)				
		Internal Events	**Internal Flood**	**Total[1]**
	DG Out of Service (OOS)	8.91E-08	7.45E-08	1.64E-07
	ICLERP[3]	5.98E-10	8.50E-10	1.45E-09[7]

Notes:
(1) The contribution from Fire, High Winds, Seismic and Other External Hazards to baseline CDF / LERF values was evaluated qualitatively in Section 4.1
(2) The ICCDP values were calculated using the following equation:
ICCDP = (OOS case – Base case) * (14/365)
(3) The ICLERP values were calculated using the following equation:
ICLERP = (OOS case – Base case) *(14/365)
(4) Total CDF meets the RG 1.174 acceptance criteria of < 1E-4 per year
(5) Total ICCDP meets the RG 1.177 acceptance criteria of < 1E-6 per year
(6) Total LERF meets the RG 1.174 acceptance criteria of < 1E-5 per year
(7) Total ICLERP meets the RG 1.177 acceptance criteria of < 1E-7 per year

4.0 QUALITATIVE CONSIDERATIONS

4.1 External Hazards

NRC RG 1.200 (Reference 4), Section 1.2.5, recognizes that hazards with low contributions to risk may be screened out of the detailed PRA modeling. WCNOC utilizes a systematic, site-specific screening process for WCGS. To support the permanent extension of the DG Completion Time, the criteria and basis for each screened hazard were reviewed. This review focused on determining if the screening was potentially impacted by changing the assumed availability of a DG. Only seismic and high winds hazard screenings were determined to warrant further review.

Seismic

The IPEEE (Reference 6) used a Seismic Margins Assessment (SMA) with a screening capacity of 0.3g for SSCs and the following considerations:

- Path success is defined as the ability to achieve and maintain a stable hot or cold shutdown condition for at least 72 hours following the seismic event.
- Offsite power is assumed failed and unrecoverable for 72 hours.
- Small Break LOCA equivalent to a one-inch diameter line break from leakage from instrument line breaks, not failures of primary system piping, is assumed.

The DG building is a Category I structure. The seismic Category I structures house or support Category I equipment and, therefore, maintaining their structural integrity is considered essential for the ability to safely shut down the plant in the event of a design basis earthquake or review level earthquake. All of the seismic Category I structures are founded on shallow soil columns over bedrock.

The DG building is a single-story, rectangular, structural steel and reinforced concrete structure which houses the standby DGs, fuel oil day tank, exhaust silencers, and exhaust stacks.

The foundation for the DG building is a 10.5-foot-thick base mat located 10 feet below plant grade. The highest portion of the roof is 66.5 feet above plant grade. The roof is a reinforced concrete slab supported by structural steel beams and girders. The roof framing is supported by reinforced concrete bearing walls and steel columns. The roof and exterior walls are designed to prevent penetration by tornado-generated missiles.

In accordance with the screening guidelines in EPRI NP-6041-SL (Reference 7), Table 2-3, the seismic Category I structures can be screened-out with a HCLPF capacity of 0.30g pga without any seismic margin evaluation if the design considers an SSE of 0.10g or greater. On this basis, the Category I structures identified above at WCGS are considered seismically rugged and assigned a minimum HCLPF capacity of 0.30g pga.

The SMA walkdown verified that the engine and generator are attached to a common stiff skid and have an adequate structural assembly for resisting lateral loads. No concerns were identified with respect to potential relative motion of interconnecting fuel, lube oil, and water cooling lines. The anchorage was visually inspected and found to match details shown on design drawings and considered in existing qualification documentation. There were no seismic interaction concerns identified. Since the Class 1E DGs satisfied the EPRI NP-6041-SL (Reference 7) screening criteria and guidelines, they were screened out and assigned a minimum HCLPF of 0.3g pga in the SMA.

A loss of offsite power (LOOP) is the primary impact expected as a result of a seismic event. Following a LOOP, all signals required to actuate the engineered safety features (ESF) are automatic and no manual operator response is required unless automatic actuation has failed. Since the seismic-induced failure of the DGs is correlated, one DG being OOS does not impact the seismic response and therefore the change in risk associated with a DG being OOS for the extended Completion Time is equivalent to the change in risk from the internal events model for random failures. In addition, the frequency of a seismic occurrence over the 14 day extended Completion Time is considered small and when considering that a train of safety related equipment would remain available the overall change in risk due to the extended Completion Time can be considered small. Furthermore, while offsite power recovery is not typically credited over the standard mission time following a seismic event, since the extended Completion Time is greater than 72 hours, it is possible that if a seismic event did occur offsite power may be able to be restored within this time frame.

<u>High Winds</u>

The IPEEE (Reference 6) for high winds focused on definition of climatic conditions which affect the plant site, evaluation of high wind loading, evaluation of tornadic wind loading and evaluation of tornado-generated missiles.

The evaluation was performed by comparison of the WCGS design to the Standard Review Plan (SRP) requirements and by confirmatory walkdowns which focused on outdoor facilities which could be affected by high winds. The evaluation confirmed that the WCGS design conforms to the SRP criteria. The walkdowns did not reveal potential vulnerabilities not considered in the original design basis.

The DG building is a single-story, rectangular, structural steel and reinforced concrete structure which houses the standby DGs, fuel oil day tank, exhaust silencers, and exhaust stacks. The DG building is a Category I structure. The general floor area of the DG Building is separated into trains A and B by a Category I, missile-resisting wall.

According to the Wolf Creek Updated Safety Analysis Report (USAR) (Reference 8), all seismic Category I structures which are required for post-accident safe shutdown, contain equipment required for post-accident safe shutdown, are required to protect reactor coolant system integrity, or which protect stored fuel assemblies are designed to withstand the effects of a tornado and the most severe wind phenomena encountered at the site (General Design Criterion (GDC)-2).

Category I structures are designed to withstand straight winds and tornadoes. The design parameters for tornadoes are given in Section 3.3.2.1 of Reference 8. In summary, Category I structures are designed to withstand tornado winds up to 360 mph and a differential pressure of 3.0 psi at a linear rate of 2.0 psi per second (Reference 8). Category I structures are designed for straight winds up to 100 mph at 30 feet above ground for a 100-year recurrence interval (Reference 8).

Based on the design criteria for Category I structures, equipment located inside of Category I structures is not vulnerable to failures due to direct missile strikes, differential pressure or straight wind loading. The maximum wind speed considered in the high winds analysis is 360 mph, corresponding with the maximum wind speed in the design-basis tornado for WCGS (Section 3.3.2.1, Reference 8). This wind speed exceeds the upper-bound of the strongest tornado in both the Fujita scale and the Enhanced Fujita scale; a tornado stronger than an F5/EF5 is not credible (Reference 9).

The concrete spalling failure mode is considered to be the only valid failure mode for equipment housed within Category I structures. Spalling is defined as the ejection of concrete or other wall debris from the interior side of a wall as a result of missile impact on the exterior side of the wall. This failure mode may impact equipment located on or near a wall that is exposed to the outside. Possibly impacted equipment includes:

- Wall-mounted equipment where spalling due to missile strikes can knock it off the wall.
- Floor equipment where wall-mounted equipment can fall onto it.
- Floor equipment where concrete debris from the wall can damage it.

It is assumed that equipment located more than several feet away from an exterior-facing, Category I wall cannot be directly affected by high wind or tornado events. Additionally, the doors separating Category I structures from the plant exterior and from Non-Category I structures are missile doors. These doors can be credited with preventing missiles from entering the structure. Equipment housed below-grade is not susceptible to external missile hits that would result in any spalling and as such need not be considered.

Based on the design of the DG Building and the separation of train A and train B to protect against missiles, spalling from a single missile strike cannot fail both DGs. The change in risk associated with a DG being OOS for the extended Completion Time is therefore equivalent to the change in risk from the internal events model for random failures plus the probability of a high wind events where spalling from a missile strike on the DG Building fails the in-service DG. Given that the frequency of such a high wind event occurrence over the 14 day extended Completion Time is

considered small the overall change in risk due to the extended Completion Time can be considered small.

Fire

The IPEEE (Reference 6) for internal fires focused on initial screening, determination of ignition source frequencies, compartment interactions analysis and plant walkdown. The approach implemented by WCNOC for the IPEEE evaluation of internal fire used the EPRI FIVE two-phase progressive screening methodology to identify risk-significant fire areas.

If there are areas of the plant that can experience internal fires that damage the capability to receive offsite power to the safeguards buses, the risk due to fires in these areas will be increased somewhat if it is assumed that the onsite DGs are more likely to be OOS for maintenance (that is, due to having an extended TS Completion Time).

The only location identified from the IPEEE fire evaluation which could cause a LOOP event is a fire in the communications corridor. A fire in this location could cause a loss of power feed cables from both ESF transformers (XNB01 & XNB02) and a loss of power feed from the #7 transformer, which would result in a loss of all offsite power condition to the plant.

The fire areas and rooms that were initially evaluated considering an LSP initiating event were:

Fire Area	Compartment
CC-IF	Communications corridor
CC-ID	Communications corridor

The CC-ID area was initially evaluated as an LSP initiator as the power feed cables from both ESF transformers could be lost as could the control cables for the service water pumps providing support for main feedwater operation.

In addition, a partial LOOP was modeled for several of the yard transformers and the turbine building general area. A fire in these areas is considered to fail one of the two main offsite power supplies.

When evaluating the potential risk increase due to internal fires in light of the proposed TS Completion Time extension for the DGs, the following should be considered:

- The extension of the TS Completion Time for the DGs is an administrative change only and does not have any significant impact on the likelihood of occurrence of fires at WCGS, or on their location within the plant.

- The only purpose for the DGs (relative to plant safety) is to start and run to provide onsite power to its associated Class 1E bus in the event that offsite power is lost.

- The likelihood of a fire resulting in a complete station blackout is low at WCGS. The IPEEE analysis identified only one location (communications corridor) in which a complete LOOP could occur. In all other areas, a complete LOOP requires additional equipment failures. Without additional failures, normal offsite power to these buses remains available. The capability to avoid SBO from the fire-related LOOP events is due to the availability of the dedicated DG.

Based on this qualitative assessment the overall change in risk from fire due to the extended Completion Time can be considered small.

4.2 Shutdown Events Considerations

WCNOC does not maintain a shutdown PRA model. WCGS operates under a shutdown risk management program to support implementation of NUMARC 91-06 (Reference 5). The shutdown risk management implementing procedure provides guidelines for outage risk management which focuses on proper planning, conservative decision-making, maintaining defense in depth, and controlling key safety functions.

5.0 RISK ASSESSMENT SUMMARY REPORT COMPLETION TIME EXTENSION OF DGS

5.1 Purpose

The purpose of this report is to document the technical adequacy of the WCGS PRA models and the acceptability of the analyses performed to support the implementation of the permanent extension of the TS Completion Time to restore the standby DGs to operable status from 72 hours to 14 days.

5.2 PRA Scope, Applicability and Acceptability

WCNOC employs a multi-faceted, structured approach in establishing and maintaining the technical adequacy and plant fidelity of the PRA models. This approach includes a robust PRA maintenance and update process, as well as the use of independent peer reviews. The following information describes this approach as it applies to the WCGS PRA.

5.3 PRA Scope

WCNOC has peer reviewed PRA models for Internal Events and Internal Flooding evaluating both core damage frequency (CDF) and large early release frequency (LERF). WCNOC is currently developing a Fire PRA (FPRA) and Seismic PRA (SPRA), however, the models are still under development and have not yet been peer reviewed.

WCNOC has also developed a High Winds PRA Model and conducted an External Events Screening Assessment in accordance with Parts 6 and 7 of the ASME/ANS PRA Standard (Reference 10). A peer review was performed in 2015 as documented in Reference 14 which determined that 95% of the Supporting Requirements (SRs) were considered MET at Capability Category (CC)-II or higher. However, the High Winds PRA model still has outstanding F&Os that need to be addressed. The high winds PRA is not sufficiently robust to provide direct support of risk applications.

5.4 PRA Applicability

Section 3.2 of NRC RG 1.200 (Reference 4) requires identification of the pieces of the PRA model for each hazard group that are needed to support the application. Because this evaluation impacts the safety related electrical distribution system which supports most modeled functions, all the model pieces and hazards are relevant.

5.5 PRA Acceptability

WCNOC conducted a full scope independent Peer Review on the Internal Events and Internal Flooding PRA models in June of 2019 (Reference 11). This Peer Review concluded that 98% of the SRs satisfied CC-II requirements of the ASME/ANS PRA Standard. During this Peer Review a total of thirty-four (34) findings, thirty (30) suggestions and one (1) best practice were generated. The conclusion of the review was that the WCGS PRA substantially met the ASME/ANS PRA standard (Reference 10) at CC-II, as endorsed by RG 1.200 (Reference 4), Revision 2, and could be used to support risk-informed applications.

Subsequently an Independent findings and observations (F&O) Closure was held in December 2019 to close out findings from the Internal Events and Internal Flooding Peer Review (Reference 12). This review followed the guidance in Appendix X of NEI 05-04 (Reference 13). During this review a total of thirty-three (33) of the thirty-four (34) findings from the 2019 peer review were reviewed (F&O 4-10 was not in scope). Of these findings, thirty-one (31) were determined to have been satisfactorily closed by the Independent Assessment Team (IAT) while two (2) remained OPEN. During the F&O closure review, two (2) unique F&Os were judged to be closed with a PRA upgrade, which required a focused scope peer review. This triggered a focused scope peer review of the SRs associated with the upgrade. Two (2) SRs in Part 2 and one (1) SR in Part 3 of the Standard were therefore re-peer reviewed. Following the focused scope peer review, all the involved SRs were judged to be met at CC-II or higher, however one (1) new F&O was assigned. This results in a total of four (4) open F&Os remaining (1 not in scope of the F&O closure, 2 not closed during the F&O closure and 1 new from the F&O closure upgrade reviews).

Table 2 lists the four (4) remaining open finding-level F&Os for the Wolf Creek PRA models (three (3) F&Os from the original peer review and one (1) F&O from the focused scope peer review conducted during the NEI 05-04 Appendix X closure). The table indicates the F&O number, the relevant SRs from the ASME/ANS PRA Standard that each F&O pertains to, the F&O text, a summary of the actions taken to address each F&O’s concern, and an evaluation of what, if any impact, there may be to the assessment of DG Completion Time extension from 72 hours to 14 days.

Table 2: Assessment of Open Finding-Level F&Os for the Wolf Creek Internal Events PRA Model

F&O Number	SR (status)	F&O Description	Resolution	Impact on DG Completion Time Extension
3-8	AS-C3 (Met) HR-I3 (Met) IE-D3 (Met) SC-C3 (Met) SY-C3 (Met) QU-F4 (Not Met)	<u>Description:</u> Identify plant specific sources of uncertainty. This identification can be documented in a manner similar to the tables that characterize the generic sources of model uncertainty and related assumptions. <u>Basis</u>: Sources of uncertainty are required to be identified. <u>Possible Resolution:</u> Identify plant specific sources of uncertainty. This identification can be documented in a manner similar to the tables that characterize the generic sources of model uncertainty and related assumptions.	The F&O was originally generated due to a lack of a clear method for identification and characterization of key plant-specific assumptions and sources of uncertainty. To resolve this F&O, WCNOC collected and characterized plant-specific sources of uncertainty in the individual PRA notebooks. However, the F&O review team (Reference 11) did not agree that this resolution was sufficient to fully close this F&O. The IAT indicated that there was a gap in the quantitative assessment of uncertainty in the quantification notebook; especially for assumptions marked as "non-conservative," which needed a statement on the importance on the results to ensure that risk insights are not masked. Specifically, assumptions marked as "non-conservative" need to have a clear characterization of the impact on results to ensure that risk insights are not masked. Although the assumptions were identified and characterized in the individual PRA notebooks, there was not a clear process used to evaluate the impact of the assumptions and sources of uncertainty in the quantification notebook. As a result, this F&O remains open. WCNOC's position is that the main issue of identification and characterization has been resolved through the identification and qualitative characterization in each PRA notebook. The quantitative characterization process is now being consolidated and more clearly documented.	Given that this F&O is understood not to have any impact on the PRA model, it is also not expected to have any adverse impact on the DG Completion Time extension.

Table 2: Assessment of Open Finding-Level F&Os for the Wolf Creek Internal Events PRA Model

F&O Number	SR (status)	F&O Description	Resolution	Impact on DG Completion Time Extension
4-10 (F&O was not in scope for the F&O closure)	LE-C13 (Met CCII-III)	Description: The approach to scrubbing of SGTR releases is consistent with the CC-II requirements and, therefore, allows the SR to be considered MET at CC-II. However, the current SGTR documentation does not provide sufficient technical basis to justify the credit taken. Additionally, the simplified approach for ISLOCA releases does not discuss any consideration of potential scrubbing credit. Basis: Additional documentation of SGTR scrubbing is needed. The approach taken for ISLOCA releases does not credit scrubbing. While CC-II/III does not require credit for ISLOCA scrubbing, some consideration for significant ISLOCA sequences is needed to meet more than CC-I. Possible Resolution: For ISLOCA events: Identify significant ISLOCA sequences and document some consideration of scrubbing for significant release locations based on the general configuration and location of subject piping systems. If credit is justifiable, document credit of radionuclide scrubbing. If scrubbing is not justifiable, document the consideration given. For SGTR events: Provide additional documentation of the engineering basis by citing appropriate plant-specific or generic analyses.	In general, the position taken on scrubbing for Steam Generator Tube Ruptures (SGTRs) and ISLOCAs is conservative. The Wolf Creek LERF PRA model only treats those SGTRs where steam generator (SG) isolation has failed as generating a large early release. With successful SG isolation, the containment is not completely bypassed and therefore these SGTRs do not result in a Large Early Release. In the case of failed SG isolation, fission product scrubbing via secondary side inventory is not realistic for most scenarios due to the uncertainty of the leak location and the availability of a sufficient water pool above the leak to scrub fission products from a potential release. No credit for scrubbing is taken for ISLOCA sequences. Crediting scrubbing for ISLOCA sequences requires complex modeling of the release pathway through the Auxiliary Building in order to track fission product plate out prior to offsite release. This is considered to be beyond state of practice in the industry.	The impact of these conservative assumptions is expected to be minimal and will be treated as areas of uncertainty in the LERF model. It is not expected to have any adverse impact on the DG Completion Time extension.
6-8	SY-C2 (Met)	Description: The notebook states that walkdowns and interviews were performed but not documented. Without the documentation there is no evidence that these tasks were performed and	All system notebooks have been reviewed by the system engineer and no significant feedback has been noted that would impact the model or this application.	Given that this F&O is understood not to have any impact on the PRA model, it is also not expected to have any

Table 2: Assessment of Open Finding-Level F&Os for the Wolf Creek Internal Events PRA Model

F&O Number	SR (status)	F&O Description	Resolution	Impact on DG Completion Time Extension
		that the walkdown was included the present as built plant. <u>Basis:</u> There is no evidence that a walkdown or operator interview was performed and when these tasks were performed. <u>Possible Resolution:</u> The results of the walkdowns and interviews should be included in the system analysis documentation.		adverse impact on the DG Completion Time extension.
AS-B3-01	AS-B3 (Met)	<u>Description:</u> Feed and Bleed scenarios involving open PORVs did not consider the potential for sump strainer blockage. The review identified no model logic or a documented basis that would address open PORV transients including considerations of the complications associated with containment sump blockage with the actuation of containment spray. <u>Basis:</u> A review of plant documentation and event tree models did not result in evidence of treatment of Feed and Bleed scenarios where sump plugging cases with the possibility of spray actuation were considered. As an example, the application or disposition of SUMP-NPSH-NONLOCA to Feed and Bleed sequences with open PORVs is not addressed. <u>Possible Resolution:</u> Add to the model or document the basis for not modeling containment sump blockage for Feed and Bleed scenarios.	The Revision 9 MOR explicitly accounts for sump blockage for LOCA events, including consequential pressurizer PORV and RCP seal leak events. This F&O was generated because other non-LOCA type events that credit Feed and Bleed through the pressurizer PORV may also experience sump blockage that is not accounted for. A sensitivity was conducted on the Revision 9 MOR to determine the impact of not limiting sump blockage to LOCA type events. The results revealed only a slight increase in CDF (0.025%) and no change at all to LERF.	Given that this F&O has a negligible impact on the PRA model, is it not expected to have an impact on the DG Completion Time extension.

5.6 PRA Level of Detail and Plant Representation

The WCGS models contain adequate detailed modeling for this application and are kept up to date with the as-built as-operated plant as described herein.

5.7 Level of Detail in the WCGS Models

The PRA model is highly detailed and includes a wide variety of initiating events, mitigation and support systems as well as fully developed common cause events. The PRA Quantification process used is based upon the large linked fault tree methodology, which is a well-known and accepted methodology in the industry. The model is maintained and quantified using the Electric Power Research Institute (EPRI) Risk and Reliability suite of software programs.

5.8 PRA Maintenance and Update Process

The WCGS PRA models are controlled and maintained in accordance with a series of Desktop Guidance documents in compliance with the requirements provided in Section 1-5 of the ASME/ANS PRA Standard RA-Sa-2009 (Reference 10). While a wide array of desktop guidance documents have been developed to govern all aspects of the WCGS PRA program the primary desktop guidance documents used to facilitate this Maintenance and Update process are PRA-DG-01, PRA-DG-02, PRA-DG-03 and PRA-DG-07 (References 16 through 19). These documents were reviewed during the Internal Events and Internal Flooding Peer Review (Reference 11) as part of a review of the WCNOC compliance with the ASME/ANS PRA Standard requirements for PRA configuration and control (Section 1-5 of Reference 10). The program was determined to meet the intent of the ASME/ANS PRA Standard confirming that a robust and detailed process is in place to identify and track pending changes.

PRA-DG-01: Probabilistic Risk Assessment Program

- This Desktop Guidance establishes the structure under which the WCGS PRA program is developed and maintained.
- The PRA program develops and maintains the WCGS PRA model of record (MOR) and, as deemed appropriate, an interim model. Additionally, the PRA program provides input to various risk-informed applications.

PRA-DG-02: Maintenance and Update of PRA Models

- This Desktop Guidance establishes the maintenance and update process for the WCGS PRA model in support of PRA-DG-01 (Reference 16). Through systematic reviews of plant changes, PRA analysts identify impacts, determine significance and schedule timely implementation.
- Model updates occur on a periodic basis. Maintenance of the PRA model is performed to ensure the PRA model continually matches the as-built, as operated plant. Focused updates are primarily driven by specific plant changes/modifications. Maintenance of the PRA model is performed to ensure model fidelity such that risk-informed decisions better support safe and reliable plant operation. In addition, planned periodic updates of broader scope also occur as driven by data review, methodology changes, external inputs or other

considerations. Less significant changes are tracked for cumulative effect to be implemented during one of the planned or maintenance updates.

PRA-DG-03: MSPI Basis Document Update

- This Desktop Guidance documents the process used to ensure that the evaluation of pending changes that impact the PRA under PRA-DG-02 are in compliance with Industry MSPI Requirements for Technical Adequacy (MSPI FAQ 14-01 (Reference 15)).

- A living model is maintained to ensure that the cumulative impact of any pending model changes is well understood so that the MOR represents the as-built as-operated plant.

PRA-DG-07: Applications Maintenance

- The purpose of this desktop guideline is to assist individuals in applying insights from the WCGS PRA model(s) to risk inform plant activities and implement beneficial risk-informed applications.

- The desktop guidance identifies the means to apply PRA insights to improve the effectiveness of processes and strengthen risk-informed decision-making in a variety of contexts.

As discussed above, these documents define the process to be followed to implement scheduled and interim PRA model updates and to control the PRA model files. In addition, these documents also define a rigorous process for identifying, tracking, and implementing model changes, and for identifying and tracking model improvements or potential issues that may affect the model. Model changes that are identified are tracked via a Configuration and Control Database which is discussed in considerable detail in PRA-DG-02 (Reference 17).

To ensure that the current PRA model remains an accurate reflection of the as-built, as-operated plant, the following activities are routinely performed:

- Design changes and procedure changes are reviewed for their impact on the PRA model.

- New engineering calculations and revisions to existing calculations are reviewed for their impact on the PRA model.

- Maintenance unavailabilities are captured, and their impact on the PRA is assessed.

- Plant specific initiating event frequencies, failure rates, and maintenance unavailabilities are updated, typically every two (2) refueling cycles.

In accordance with this guidance, regularly scheduled PRA model updates occur typically every two refueling cycles with more frequent updates occurring based on the risk significance of permanent changes, initiating events, and failure data such that the PRA continues to adequately represent the as-built, as-operated plant.

5.9 Risk Application PRA Model

The current approved version of the WCGS Internal Events and Internal Flooding model is the Revision 9 MOR.

WCGS thoroughly tracks pending changes in a Configuration and Control Database so any outstanding items can be evaluated in a quarterly Mitigating System Performance Index (MSPI) rollup in accordance with PRA-DG-03. This Configuration and Control Database contains a reporting feature that can be used to quickly return all entries that are pending model changes that need to be considered.

Subsequent quarterly updates and evaluations are then made directly to the previously developed MSPI Living Model (hence the term “Living”) to ensure that this model represents the cumulative impact of all pending changes since the MSPI Record Model was released in accordance with MSPI FAQ 14-01 (Reference 15).

The current Living Model version (Reference 20) has incorporated all outstanding impacts assessed for MSPI as of December 31, 2020 and was therefore used to support this amendment request.

5.10 DG Cases and Quantification Setup

To ensure that the full impact of the OOS DG was captured properly, all basic events (BE) associated with each DG were set to TRUE in each DG OOS case. Maintenance on the other DG was also set to FALSE in the evaluated cases for each DG OOS. In addition, the CCW service loop event flags were set to TRUE and FALSE for the in-service DG and OOS DG, respectively. This aligns with the plant procedure AI 22C-013, “Protected Equipment Program.”

Flag files were utilized to set the BEs for each OOS case. For example, for NE01 OOS, the following BEs were set to TRUE:

- NE-EDG-TAM-NE01
- NE-EDG-FTR-NE01
- NE-EDG-FTS-NE01
- NE-EDG-FLR-NE01

And the following BE was set to FALSE:

- NE-EDG-TAM-NE02

The following settings were used for NE01 OOS to set the CCW event alignment as follows:

- EG-CP-CCWA-SERVLP EQU .F.
- EG-CP-CCWB-SERVLP EQU .T.

For NE02 OOS, a similar flag file was used with opposite train settings. CDF case results were reported at 1E-12 and LERF case results were reported at 1E-14, which is consistent with the baseline results that showed adequate truncation.

Note that CCF failures were not changed as they have the same impact within the model (combined with BE with an OR gate). Modifying the CCF events would have no impact on the results or on the conclusions of this analysis.

For the sensitivity when the Sharpe Station is assumed to be unavailable, basic event SH-BUS-ACO-SOUTH was chosen to represent failure in the model as this has the same impact as failing the operator action without impacting HRA dependency.

The maintenance event probabilities for the diesels were not adjusted in the base model case since the maintenance events are an average of OOS time over several operating cycles. This is conservative because the events are either set to TRUE or FALSE in the evaluation cases, so increasing the values in the base models would increase the base risk and not impact the case risk, decreasing the calculated delta risk. Note that the ICCDP and ICLERP deltas were calculated using 14 day duration, rather than the change from 72 hours to 14 days (11 day duration), which provides another source of conservatism.

Tier 1 – DG Risk Evaluation Results and Insights

As defined in NRC RG 1.177 (Reference 2), Tier 1 is the evaluation of the impact on plant risk of the proposed TS change as expressed by the risk metrics discussed below. The following sections present the results of those quantitative risk analyses.

The risk metrics of interest for permanent changes to TSs are the ICCDP and the ICLERP. The application specific model (ASM) was used for internal events and internal flooding.

5.11 <u>Risk Insights</u>

The difference between the baseline results in normal alignment and the DG OOS cases are consistent with the flag file changes described in Section 5.10 incorporated into the individual cases for NE01 and NE02.

Overall, the ICCDP and ICLERP results (See Table 1) were approximately 1 to 2 orders of magnitude below the requirements of the regulatory guide, respectively. This was anticipated given that there is inherent defense-in-depth at WCGS in the scenario in which a DG is unavailable, due to the available SBO DG System which consists of three non-safety related DGs that are capable of supplying essential loads on Class 1E busses NB01 or NB02.

In addition, there is the currently available Sharpe Station which is an AC electrical power generating unit and functions primarily to generate AC power during periods of peak electrical demand. If necessary, the Sharpe Station is also available to provide backup AC power to the WCGS.

Given that there is a plant modification under development that will result in removal of the capability to align the Sharpe Station as a backup to the DGs, a sensitivity was performed and results are in Section 5.12. Overall ICCDP and ICLERP showed a very minor increase with the removal of the Sharpe Station.

5.12 <u>Sensitivities</u>

<u>Unavailability of the Sharpe Station</u>

A sensitivity was run to take the Sharpe Station OOS. The ICCDP and ICLERP risk quantification results for this case are presented in Table 3 and are based on a DG restoration Completion Time of 14 days. For this case, basic event SH-BUS-ACO-SOUTH chosen to represent failure in the

model as this has the same impact as failing the operator action without impacting HRA dependency analysis.
A flag file was used to set the model for the sensitivity and the following was added to the flag file settings described in Section 5.10:

- SH-BUS-ACO-SOUTH prob 1

The component failure is set to 1.0 rather than true for the sensitivity to indicate component failure that will be visible in cutsets if a large increase in CDF or LERF was found. As it was only one failure, impact from non-minimal cutsets was low and model run time was not greatly impacted.

Overall, the ICCDP and ICLERP results (See Table 3) were approximately 1 to 2 orders of magnitude below the requirements of the regulatory guide, respectively. This was anticipated given that there is inherent defense-in-depth at WCGS in the scenario in which a DG is unavailable, due to the available SBO DG System which consists of three non-safety related DGs that are capable of supplying essential loads on Class 1E busses NB01 or NB02.

Overall ICCDP and ICLERP showed a very minor increase with the removal of the Sharpe Station.

Table 3: ICCDP and ICLERP Results for DG Completion Time Extension from 72 hours to 14 Days (Sharpe Station Unavailable)

		Internal Events	Internal Flood	Total(1)
DG NE01				
CDF	**Base Case**	6.68E-06	1.20E-05	1.87E-05(4)
	DG NE01 Out of Service	8.80E-06	1.66E-05	2.54E-05
	ICCDP(2)	8.14E-08	1.77E-07	2.58E-07(5)
LERF	**Base Case**	7.35E-08	5.24E-08	1.26E-07(6)
	DG NE01 Out of Service	9.71E-08	7.46E-08	1.72E-07
	ICLERP(3)	9.06E-10	8.54E-10	1.76E-09(7)
DG NE02				
CDF	**Base Case**	6.68E-06	1.20E-05	1.87E-05(4)
	DG NE02 Out of Service	8.17E-06	1.69E-05	2.51E-05
	ICCDP(2)	5.71E-08	1.89E-07	2.47E-07(5)
LERF	**Base Case**	7.35E-08	5.24E-08	1.26E-07(6)
	DG NE02 Out of Service	8.93E-08	7.45E-08	1.64E-07
	ICLERP(3)	6.07E-10	8.50E-10	1.46E-09(7)

Notes:
(8) The contribution from Fire, High Winds, Seismic and Other External Hazards to baseline CDF / LERF values was evaluated qualitatively in Section 4.1
(9) The ICCDP values were calculated using the following equation:
ICCDP = (OOS case – Base case) * (14/365)
(10) The ICLERP values were calculated using the following equation:
ICLERP = (OOS case – Base case) *(14/365)
(11) Total CDF meets the RG 1.174 acceptance criteria of < 1E-4 per year
(12) Total ICCDP meets the RG 1.177 acceptance criteria of < 1E-6 per year
(13) Total LERF meets the RG 1.174 acceptance criteria of < 1E-5 per year
(14) Total ICLERP meets the RG 1.177 acceptance criteria of < 1E-7 per year

5.13 Review of Assumptions and Uncertainty

5.13.1 Identification of Key Assumptions

A review of assumptions in the hazard model calculations was performed to identify applicable assumptions to this amendment request.

The following assumptions were identified as a potential impact and were evaluated further with respect to this amendment request:

- The WCGS model only credits operation of the TDAFWP for eight hours following SBO. The batteries for the TDAFWP and SG level indication are analyzed to provide DC power to these components for a minimum of eight hours with no AC support. No credit for equipment operation after battery depletion represents a conservative bias. A review of the results summarized in Table 1 reveals that battery depletion is indeed having an impact on the results, specifically with internal flooding (FG-BATDEPLNK12). Operation of the TDAFWP following loss of DC power would be challenging, especially for an internal flooding scenario. Therefore, it is expected that only limited improvement would be seen when adding additional credit to the model for such a scenario. Given that the currently conservative results are already demonstrating acceptance this was determined to be unnecessary for this application.

- The external leak small (LSELS) sequencer boundary as specified in NUREG/CR-6928 includes "the relays, logic modules, etc. that comprise the sequencer function of the emergency DG load process." However, the load shed and loading relays are conservatively modeled as separate components to facilitate risk assessments for configuration risk management and for regulatory risk assessments in the event of an individual relay failure. This approach results in double counting of the relay failures since the industry data for sequencers includes associated relays. The sequencer and sequencer relay failures were confirmed not to be significant to the results for this application.

- The minimum reactor coolant pump (RCP) seal leakage rate used to determine the time available for AC power recovery in the MAAP cases with failure of the normal RCP seal package is 76 gpm per pump. This was used to bound the uncertainty in the flow rates through the seal package as RCS pressure is reduced. The AC power recovery factors determined based on the 76 gpm per pump leakage rate is applied to sequences with either 21 gpm per pump or 76 gpm per pump leakage rates, which is conservative. This is a conservative leak rate, especially given the expected performance of the SHIELD seals, and may be a source of uncertainty for applications with high RCP seal LOCA importance. A review of the results shows that this (BB-21GPM-PERRCP-SEALLEAK) is not having a significant impact on either the internal events or internal flooding models.

- The Sharpe Station gensets are assumed to be initially in standby. This assumption is either realistic or conservative depending on the time of year as the Sharpe Station may be running quite frequently in the summer months as a "peaker plant." A sensitivity has been conducted which completely removed credit for the Sharpe Station which indicated only a minor impact overall. Therefore, the assumption that the gensets need to start is determined to have a negligible impact on this application.

- The essential service water (ESW) system provides cooling support to the DGs. Using engineering judgement, it is assumed that the ESW pump bays will contain significant debris that would challenge the traveling screen function 10% of the time; basic event EF-CP-DEBRIS has been assigned a probability of 0.1. Operation of the traveling screens is only required during this period to prevent failure of the associated ESW train. This engineering judgement is based on wind being the primary driver for lake debris that would cause a significant blockage. The lake is fed almost entirely from local watershed and does not have a source that would create a significant current (i.e., river flow). The ESW screenhouse is oriented such that the intake screens are facing to the East. WCGS's location vary rarely experiences prevailing winds from the East. The Normal Service Water screens are oriented facing to the south. Winds experienced at WCGS, especially during the summer months, are predominantly from the south. Typical wind direction is supported by Section 2.3 of the Wolf Creek USAR. Therefore, the orientation of the ESW intake compared to the Normal Service Water intake is the basis for the different values chosen (NSW-DEBRIS has a value of 0.2). This is a conservative treatment since it is expected the actual conditional probability of significant debris will be much lower. The DGs are typically only dependent on the ESW system and a review of both the internal events and internal flooding results shows a negligible impact even if EF-CP-DEBRIS is set to 1.0. Therefore, this assumption was determined to have a negligible impact on this application.

- All internal flood propagation pathways were initially developed assuming an infinite source. Flooding impacts due to source volume variance will be further evaluated during the scenario development phase of this Internal Flood PRA. This is considered to have a negligible impact on this analysis because the flood source impacting the DGs are fire protection and service water. These systems both take suction from the lake rather than a tank so the flood source is essentially infinite.

- Limited credit is given in the internal flooding propagation pathways for floor drains. This was determined not to have an impact on this analysis because the DG rooms were specifically refined to develop more realistic flooding propagation scenarios where credit is given for floor drains.

5.13.2 <u>Application Specific Assumptions</u>

- Diesel generator maintenance/testing unavailability is mutually exclusive in the PRA models. That is, only one DG may be taken OOS at the same time. This assumption is consistent with TSs and the PRA models.

- The average Testing and Maintenance (TAM) is assumed in the baseline cases.

- A 14 day duration is assumed for ICCDP and ICLERP calculations, rather than the change from 72 hours to 14 days (11 day duration).

5.13.3 <u>Completeness Uncertainty</u>

Completeness uncertainty is addressed by evaluating the completeness of the risk analysis. Internal Events and Internal Flooding completeness uncertainty reviews were captured in Section 5.13.1. Because all unscreened hazards have been qualitatively screened for this application, no major form of completeness uncertainty that would impact the results of this assessment exists.

5.13.4 Parametric Uncertainty

Parametric uncertainty is typically evaluated by use of software tools designed for this purpose, such as UNCERT, which propagate the parametric uncertainties of each PRA model input through the model to estimate a mean risk metric result rather than a point estimate. The component failure and common cause basic events in the WCGS models are constructed to facilitate the state of knowledge correlation during the uncertainty calculations.

The evaluation of parametric uncertainty determined that the parametric uncertainty results on the current PRA MOR show a propagated mean estimate that is very near, and only slightly greater than, the point-estimate based mean. In addition, the propagated mean estimate is based on uncertainty parameter inputs that are largely generic or assumed values, so the propagated mean is not necessarily a better risk estimate. For this analysis, basic events related to the OOS DG are set to TRUE and the CCW service loop alignment was set to TRUE and basic events pertaining to prohibitive maintenance were set to FALSE, all other basic retained their original values and parametric values. Therefore, since the specific changes due to this application do not directly impact parametric uncertainties, the point-estimate based mean risk results are judged to be appropriate for this application and no additional parametric uncertainty calculations were performed.

6.0 REFERENCES

1. Regulatory Guide 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis."

2. Regulatory Guide 1.177, Revision 2, "Plant-Specific, Risk-Informed Decision making: Technical Specifications."

3. Regulatory Guide 1.160, Revision 4, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

4. Regulatory Guide 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities."

5. NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," December 1991.

6. Wolf Creek Generating Station, "Individual Plant Examination of External Events (IPEEE), June 1995."

7. EPRI NP-6041-SL, Revision 1, "A methodology for Assessment of Nuclear Power Plant Seismic Margin."

8. Wolf Creek Updated Safety Analysis Report, Revision 33, March 2020.

9. "A Recommendation for an Enhanced Fujita Scale (EF-Scale)," June 2004, Wind Science and Engineering Center, Texas Tech University.

10. ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," February 2009.

11. WCNOCPES029-REPT-001, Revision 0, “Wolf Creek Internal Events Probabilistic Risk Assessment Peer Review.”

12. PWROG-19038-P, Revision 0, “Independent Assessment of Facts and Observations Closure of the Wolf Creek Probabilistic Risk Assessment.”

13. NEI 05-04, Revision 3, “Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard,” Nuclear Energy Institute, November 2009.

14. PWROG-15082-P, Revision 0, “Peer Review of the Wolf Creek Generating Station External Events Screening and High Winds Probabilistic Risk Assessment.”

15. FAQ 14-01, “MSPI PRA Technical Adequacy,” Effective 3/31/2016.

16. PRA-DG-01, Revision 0, “Probabilistic Risk Assessment Program.”

17. PRA-DG-02, Revision 1, “Maintenance and Update of PRA Models.”

18. PRA-DG-03, Revision 0, “MSPI Basis Document Update.”

19. PRA-DG-07, Revision 0, “PRA Applications.”

20. LTR-RAM-21-03, Revision 0, “Archival of the Wolf Creek 2020Q4 Living Model to support the EDG LCO Extension Application.”

ATTACHMENT III

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)		Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore offsite circuit to OPERABLE status.	~~-----------NOTE------- A Completion Time of 10 days from discovery of failure to meet the LCO may be used with the 7 day Completion Time of Required Action B.4.2.2 for an inoperable DG. --------------------------~~ 72 hours AND ~~6~~ 17 days from discovery of failure to meet LCO
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Verify the required Station Blackout (SBO) DGs are available.	1 hour AND Once per 8 hours thereafter
	AND		

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	3 B.~~2~~	--------------NOTE-------------- In MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. -------------------------------------	
		Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
4	B.~~3~~.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	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
	<u>AND</u>		
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	~~-----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. -----~~ B.~~4.1~~ 5 Restore DG to OPERABLE status. ~~OR~~ ~~B.4.2.1 Verify the required Sharpe Station gensets are available.~~ ~~AND~~ ~~B.4.2.2 Restore DG to OPERABLE status.~~	~~72 hours~~ 14 days AND ~~6~~ 17 days from discovery of failure to meet LCO ~~Once per 12 hours~~ ~~7 days~~ ~~AND~~ ~~10 days from discovery of failure to meet LCO~~
C. Required Action B.~~4.2.1~~ 2 and associated Completion Time not met.	C.1 Restore DG to OPERABLE status~~.~~ or restore required SBO DGs to available status.	72 hours from discovery of unavailability of required SBO DGs OR 24 hour from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of required SBO DGs

(continued)

NO CHANGES THIS PAGE. INFORMATION ONLY.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two offsite circuits inoperable.	D.1 --------------NOTE-------------- In MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. ------------------------------------ Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition D concurrent with inoperability of redundant required features
	AND	
	D.2 Restore one offsite circuit to OPERABLE status.	24 hours
E. One offsite circuit inoperable. AND One DG inoperable.	-------------------NOTE---------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition E is entered with no AC power source to any train. ---	
	E.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	E.2 Restore DG to OPERABLE status.	12 hours
F. Two DGs inoperable.	F.1 Restore one DG to OPERABLE status.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One load shedder and emergency load sequencer inoperable.	G.1 Declare affected DG and offsite circuit inoperable. AND G.2 Restore load shedder and emergency load sequencer to OPERABLE status.	Immediately 12 hours
H. Required Action and associated Completion Time of Condition A, C, D, E, F, or G not met. OR Required Actions B.1, ~~B.2, B.3.1, B.3.2, B.4.1, and B.4.2.2~~ B.3, B.4.1, B.4.2, and B.5 and associated Completion Time not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours
I. Three or more required AC sources inoperable.	I.1 Enter LCO 3.0.3.	Immediately

ATTACHMENT IV

REVISED TECHNICAL SPECIFICATION PAGES

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)		Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore offsite circuit to OPERABLE status.	72 hours AND 17 days from discovery of failure to meet LCO
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Verify the required Station Blackout (SBO) DGs are available.	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3	-------------NOTE------------- In MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. ------------------------------------	
		Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.4.1	Determine OPERABLE DG is not inoperable due to common cause failure.	24 hours
	OR		
	B.4.2	-------------NOTE------------- The Required Action of B.4.2 is satisfied by the automatic start and sequence loading of the DG. ------------------------------------	
		Perform SR 3.8.1.2 for OPERABLE DG.	24 hours
	AND		

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.5	Restore DG to OPERABLE status.	14 days AND 17 days from discovery of failure to meet LCO
C. Required Action B.2 and associated Completion Time not met.	C.1	Restore DG to OPERABLE status or restore required SBO DGs to available status.	72 hours from discovery of unavailability of required SBO DGs OR 24 hours from discovery of Condition B entry ≥ 48 hours concurrent with unavailability of required SBO DGs

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. One load shedder and emergency load sequencer inoperable.	G.1	Declare affected DG and offsite circuit inoperable.	Immediately
	<u>AND</u>		
	G.2	Restore load shedder and emergency load sequencer to OPERABLE status.	12 hours
H. Required Action and associated Completion Time of Condition A, C, D, E, F, or G not met. <u>OR</u> Required Actions B.1, B.3, B.4.1, B.4.2, and B.5 and associated Completion Time not met.	H.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	H.2	Be in MODE 5.	36 hours
I. Three or more required AC sources inoperable.	I.1	Enter LCO 3.0.3.	Immediately

ATTACHMENT V

PROPOSED OPERATING LICENSE CHANGES (Markup)

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.
~~163~~	~~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.~~
~~163~~	~~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.~~
~~163~~	~~The licensee will ensure the RCP seal model from WCAP-15603, Rev. 1-A, “WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRs” is utilized in the 2002 WCGS PSA Model. The licensee will verify that the utilization of the Sharpe Station for supporting an extended DG Completion Time in the 2002 WCGS PSA Model meets the risk acceptance guidelines of Regulatory Guide 1.174 and Regulatory Guide 1.177. Additionally, the licensee will include the risk impact of the Sharpe Station in the Safety Monitor, including adding an activity to the Activity Table that will account for the impact of the plant configuration associated with crediting the Sharpe Station during the use of an extended Completion Time for pre-planned maintenance activities.~~	~~Prior to the first use of the 7-day Completion Time of Required Action B.4.2.2 of TS 3.8.1.~~

ATTACHMENT VI

REVISED OPERATING LICENSE CHANGES

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.

ATTACHMENT VII

PROPOSED TS BASES CHANGES
(for information only)

BACKGROUND (continued)

feeder breakers to the bus(es) experiencing degraded voltage. Both signals are initiated from the load shedder and emergency load sequencer (LSELS). OPERABILITY of the undervoltage and degraded voltage instrumentation functions are addressed in LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation." After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a LSELS strips non-essential loads from the ESF bus. When the DG is tied to the ESF bus, essential loads are then sequentially connected to its respective ESF bus by the load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

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

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 6201 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

INSERT B 3.8.1-2

APPLICABLE SAFETY ANALYSES

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

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon

INSERT B 3.8.1-2

The Station Blackout (SBO) DG System consists of three non-safety related DGs that are capable of supplying essential loads on ESF buses NB01 and NB02. The SBO DG System is made available to support extended Completion Times in the event of an inoperable DG. The SBO DGs are made available as a defense-in-depth supplemental source of AC power to mitigate a loss of offsite power event. The SBO DGs would remain disconnected from the Class 1E AC Distribution System unless required during a loss of offsite power or during a functional load test.

BASES

ACTIONS

A.2 (continued)

b. A required feature on the other train is inoperable and not in the safeguards position.

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

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

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

A.3

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

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

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to ~~72 hours~~. This could lead to a

14 days

BASES

ACTIONS

A.3 (continued)

total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable and an additional ~~72 hours~~ 14 days allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. Although highly unlikely, this could continue indefinitely if not limited. 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 "AND" connector between the 72 hour and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the ~~6~~ 14 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~~ 14 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 A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A "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 Completion Time is modified by a Note. The Note modifies the Completion Time and allows 10 days from discovery of failure to meet the LCO during the use of the 7 day Completion Time in Required Action B.4.2.2.~~

~~The 10 day Completion Time specified in the Note establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable using the 7 day Completion Time of Required Action B.4.2.2 and that DG is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable and an additional 72 hours allowed prior to complete restoration of the LCO. Although highly unlikely, this could continue indefinitely if not limited. The 10 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 D (see Completion Time Example 1.3-3).~~

BASES

ACTIONS

~~A.3 (continued)~~

Tracking the 10 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 10 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 A was entered. This results in the requirement, when in this Condition, to track the time elapsed from both the Condition A "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."

B.1

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

INSERT B 3.8.1-8

3

B.~~2~~

Required Action B.~~2~~ is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from the redundant AC electrical power train. This includes motor driven auxiliary feedwater pumps. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included in this Condition. A Note is added to this Required Action stating that in MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. The reason for the Note is to confirm the OPERABILITY of the turbine driven auxiliary feedwater pump in this Condition, since the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

INSERT B 3.8.1-8

B.2

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, the required SBO DGs must be verified available within 1 hour upon entry into TS 3.8.1, Condition B, and every 8 hours thereafter. SBO DG availability requires that:

a. A start/loaded test has been performed within 30 days of entry into the extended Completion Time. This portion of the Required Action evaluation is performed one time and is met with an administrative verification of this prior to a planned removal of a DG from service or after an emergent DG outage; and

b. Fuel oil tank level for each required SBO DG is verified locally to be ≥ 24 hour supply (SBO Mission Time Minimum Fuel Satisfied Light); and

c. Supporting system parameters for starting and operating each requiredd SBO DG are verified to be within required limits for functional availability (e.g., battery state of charge).

The SBO DG System is not used to extend the Completion Time for more than one inoperable DG at any one time.

3

BASES

ACTIONS

B.2 (continued)

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

a. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable and not in the safeguards position.

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

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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

4

B.3.1 and B.3.2

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

4

4

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG. Required Action B.3.2 is modified by a Note stating that it is satisfied by the automatic start and sequence loading of the DG. The Note indicates that an additional start of the DG for test purposes only, is not required if the DG has automatically started and loaded following a loss of the offsite power source to its respective bus (Ref. 18).

4

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

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

B.5

~~B.4.1, B.4.2.1, and B.4.2.2~~

INSERT B 3.8.1-10

~~In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.~~

~~The Completion Time of 72 hours for Required Action B.4.1 applies when a DG is discovered or determined to be inoperable, such as due to a component or test failure, and requires time to effect repairs, or it may apply when a DG is rendered inoperable for the performance of maintenance during applicable MODES. The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA during this period.~~

~~The second Completion Time for Required Action B.4.1 also establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable and an additional 72 hours allowed prior to complete~~

INSERT B 3.8.1-10

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources (including the required SBO DGs), a reasonable time for repairs, and the low probability of a DBA occurring during this period.

When one DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if the required SBO DGs are verified available for backup operation in accordance with Required Action B.2.

The second Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of the LCO. The 17 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 D (see Completion Time Example 1.3-3). The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

Tracking the 17 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 17 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."

Administrative controls are required whenever Condition B is entered for a planned or unplanned DG outage that will extend beyond 72 hours. Administrative controls applied ensure or require that:

a. Weather conditions are conducive to an extended DG Completion Time.

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. Elective maintenance or testing that would challenge offsite power availability is that activity that could result in an electrical power distribution system (offsite circuit or transmission network) transient or make the offsite circuit(s) unavailable or inoperable (Reference 19). The operational risk assessment procedure provides a list of equipment that could challenge offsite power availability.

c. 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).

BASES

ACTIONS

~~B.4.1, B.4.2.1, and B4.2.2 (continued)~~

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 "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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 per12 hours by locally monitoring various genset parameters.

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. 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 (Ref. 16):

a. Weather conditions are conducive to an extended DG Completion Time. The extended DG Completion Time applies during the period of September 7 through April 5.

BASES

ACTIONS ~~B.4.1, B.4.2.1, and B4.2.2 (continued)~~

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. Elective maintenance or testing that would challenge offsite power availability is that activity that could result in an electrical power distribution system (offsite circuit or transmission network) transient or make the offsite circuit(s) unavailable or inoperable (Reference 19). The operational risk assessment procedure provides a list of equipment that could 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, a minimum of 8 gensets must be capable of providing power to a dead bus (station blackout conditions) to power 1 ESF train. 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 1) crediting a running of the gensets for load for commercial reasons for greater than 1 hour, or 2) 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.

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).

If, while Required Action B.4.2.2 is being used, one (or more) of the above systems or components is determined or discovered to be inoperable, or if

BASES

ACTIONS

~~B.4.1, B.4.2.1, and B4.2.2 (continued)~~

an emergent condition affecting DG OPERABILITY is identified, re-entry into Required Action B.2 and B.3 would be required, as applicable. In addition, the effect on plant risk would be assessed and any additional or compensatory actions taken, in accordance with the plant's program for implementation of 10 CFR 50.65(a)(4). The 7-day Completion Time would remain in effect for the DG if Required Action B.2 and B.3 are satisfied.

The second Completion Time specified in Required Action B.4.2.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable, the LCO may already have been not met for up to 72 hours. If the offsite circuit is restored to OPERABLE status within the required 72 hours, this could lead to a total of 10 days since initial failure to meet the LCO, to restore compliance with the LCO (i.e., restore the DG). At this time, an offsite circuit could again become inoperable and an additional 72 hours allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. Although highly unlikely, this could occur indefinitely if not limited. 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 Example 1.3-3).

Tracking the 10 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 10 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."

C.1

INSERT B 3.8.1-13

~~If the availability of the required Sharpe Station gensets cannot be verified, the DG must be restored to OPERABLE status within 72 hours. The 72 hour Completion Time begins upon entry into Condition C. However, the total time to restore an inoperable DG cannot exceed 7 days (per the Completion Time of Required Action B.4.2.2).~~

INSERT B 3.8.1-13

If the required SBO DGs are or becomes unavailable with an inoperable DG, then action is required to restore the SBO DGs to available status or to restore the DG to OPERABLE status within 72 hours from discovery of an unavailable required SBO DG. However, if the required SBO DG unavailability occurs sometime after 48 hours of continuous DG inoperability, then the remaining time to restore the SBO DG to available status or to restore the DG to OPERABLE status is limited to 24 hours. However, the total time to restore an inoperable DG cannot exceed 14 days (per the Completion Time of Required Action B.5).

The 72 hour Completion Time only begins on discovery that both an inoperable DG exists and the required SBO DGs are unavailable. The 24 hour Completion Time only begins on discovery that an inoperable DG exists for ≥ 48 hours and a required SBO DG is unavailable.

The Completion Time of 72 hours is consistent with Regulatory Guide 1.93 (Ref. 6). The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and low probability of a DBA occurring during this period.

BASES

ACTIONS

C.1 (continued)

~~The Completion Time of 72 hours is consistent with Regulatory Guide 1.93 (Ref. 6). The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and low probability of a DBA occurring during this period.~~

D.1 and D.2

Required Action D.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These redundant required features are those that are assumed to function to mitigate an accident, coincident with a loss of offsite power, in the safety analyses, such as the Emergency Core Cooling System and Auxiliary Feedwater System. These redundant features do not include monitoring requirements, such as Post Accident Monitoring and Remote Shutdown. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps and the turbine driven auxiliary feedwater pump which must be available for mitigation of a feedwater line break. Single train features, other than the turbine driven auxiliary feedwater pump, are not included in this Condition. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. A Note is added to this Required Action stating that in MODES 1, 2, and 3, the turbine driven auxiliary feedwater pump is considered a required redundant feature. The reason for the Note is to confirm the OPERABILITY of the turbine driven auxiliary feedwater pump in this Condition, since the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

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

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable and not in the safeguards position.

BASES

ACTIONS

F.1 (continued)

According to Reference 6, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

G.1 and G.2

Required Action G.1 provides assurance that the appropriate Action is entered for the affected DG and offsite circuit if its associated LSELS becomes inoperable. An LSELS failure results in the inability of the EDG to start upon a loss of ESF bus voltage or degraded voltage condition. Additionally, LSELS trips the ESF bus normal and alternate feeder supplies and trips non-essential loads. A sequencer failure results in the inability to start all or part of the safety loads powered from the associated ESF bus and thus when an LSELS is inoperable it is appropriate to immediately enter the Conditions for an inoperable DG and offsite circuit. Because an inoperable LSELS affects all or part of the safety loads, an immediate Completion Time is appropriate.

The LSELS is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the division. The 12 hour Completion Time of Required Action G.2 provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

H.1 and H.2

B.3, B.4.1, B.4.2, and B.5

If the inoperable AC electric power sources or the load shedder and emergency load sequencer cannot be restored to OPERABLE status within the required Completion Time, or Required Actions B.1, ~~B.2, B.3.1, B.3.2, B.4.1 or B.4.2 2~~ cannot be met within the required Completion Times, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

REFERENCES (continued)

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. Not used.

16. ~~Amendment No. 163, April 26, 2006.~~ Not used.

17. Amendment No. 154, August 4, 2004.

18. Amendment No. 8, May 29, 1987.

19. Condition Report 15727.

ATTACHMENT VIII

LIST OF REGULATORY COMMITMENTS

LIST OF COMMITMENTS

The following table identifies commitments made by Wolf Creek Nuclear Operating Corporation in this document. Any other statements in this letter are provided for information purposes and are not considered regulatory commitments. Please direct questions regarding these commitments to Ron Benham, Manager Regulatory Affairs at Wolf Creek Generating Station, (620) 364-4204.

REGULATORY COMMITMENT	DUE DATE
The extended Completion Time for an inoperable DG will be used no more than once in an 18-month period (a refueling interval) on a per DG basis to perform DG planned maintenance activities.	Upon implementation of the associated amendment.
Plant procedures will be revised to include daily communications between the Transmission System Operator and control room operators on the status of the plant and the transmission system when a DG is taken out of service.	Upon implementation of the associated amendment.

ATTACHMENT IX

IMPLEMENTATION OF BRANCH TECHNICAL POSITION 8-8

IMPLEMENTATION OF BRANCH TECHNICAL POSITION 8-8

Wolf Creek Nuclear Operating Corporation (WCNOC) reviewed the Nuclear Regulatory Commission (NRC's) NUREG 0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition,” Branch Technical Position (BTP) 8-8, “Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions,” as acceptable approach to analyzing and evaluating changes for allowed outage time extensions. This Attachment discusses WCNOC's implementation of the guidance provided in BTP 8-8. WCNOC extracted the salient points from BTP 8-8 and discusses below how they have been implemented in this submittal.

IMPLEMENTATION OF BTP 8-8

What follows is a listing of the guidance provided in BTP 8-8 followed by a discussion explaining how WCNOC implemented this guidance in the requested license amendment.

1. A supplemental power source should be available as a backup to the inoperable emergency diesel generator (EDG) or offsite power source, to maintain the defense-in-depth design philosophy of the electrical system to meet its intended safety function.

   WCNOC Implementation: WCGS has an installed station blackout (SBO) diesel generator (DG) System includes three non-safety related Kohler 3250 kW DGs and one Power Equipment Center (PEC). The SBO DG System is discussed in Attachment I, Section3.4.

2. The supplemental source must have capacity to bring a unit to safe shutdown (cold shutdown)[1] in case of a loss of offsite power (LOOP) concurrent with a single failure during plant operation (Mode 1).

   WCNOC Implementation: An engineering evaluation was performed utilizing the Electrical Transient Analysis Program (ETAP) to perform load flow, short circuit, and motor starting analyses for LOOP scenarios. This is discussed in Attachment I, Section 3.4.2.

3. The time to make the AAC or supplemental power source available, including accomplishing the cross-connection, should be approximately one hour.

   WCNOC Implementation: The time to make the required SBO DGs is approximately 1 hour and is discussed in Attachment 1, Section 3.4.2.

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[1]By “cold shutdown” it is not implied that the plant needs to go to cold shutdown during LOOP. The unit can remain in either hot shutdown or hot standby in accordance with its licensing basis for the short term. However, if the offsite power is not recovered in a timely manner it may become necessary for the unit to go to cold shutdown, therefore the supplemental or AAC power source must have the capacity and capability to accomplish this function if needed.

4. The availability of AAC or supplemental power source should be verified within the last 30 days before entering extended allowed outage time (AOT) by operating or bringing the power source to its rated voltage and frequency for 5 minutes and ensuring all its auxiliary support systems are available or operational.

   WCNOC Implementation: Procedure STN KU-010, “Station Blackout Diesel and Non-Safety AFW Pump Test,” is performed monthly to demonstrate the functionality of the SBO DGs. This is discussed in Attachment I, Section 3.4.4. Additionally, the marked-up TS Bases for evaluating the required SBO DG availability includes checking the start/loaded test has been performed within 30 days of entry into the extended Completion Time. This is discussed in Attachment I, Section 3.4.3.

5. To support the one-hour time for making this power source available, plants must assess their ability to cope with loss of all AC power for one hour independent of an AAC power source.

   WCNOC Implementation: This is discussed in Attachment I, Section 3.4.2. A calculation in accordance with the guidance provided in NUMARC 87-00 demonstrated that WCNOC is a 4-hour coping plant. This calculation did not credit a supplemental AC power source.

6. The plant should have formal engineering calculations for equipment sizing and protection and have approved procedures for connecting the AAC or supplemental power sources to the safety buses.

   WCNOC Implementation: Calculation XX-E-022, SBO Diesel Generators – AC System Analysis,” analyzed the effect of adding three (3) SBO diesel generators. This is discussed in Attachment I, Section 3.4.2. Procedures SYS KU-121, “Energizing NB01 from Station Blackout Diesel Generators,” or SYS KU-122, “Energizing NB02 from Station Blackout Diesel Generators,” provide the steps for starting the SBO diesel generators and connecting them to the applicable Class 1E safety buss.

7. The EDG or offsite power AOT should be limited to 14 days to perform maintenance activities.

   WCNOC Implementation: TS Required Action B.5, Restore DG to OPERABLE status, Completion Time limits the maximum allowed outage time to 14 days.

8. The TS must contain Required Actions and Completion Times to verify that the supplemental AC source is available before entering extended AOT.

   WCNOC Implementation: TS Required Action B.2 requires verification of the availability of the required SBO DGs and the Required Action B.5 Completion Time of 14 days is contingent upon the required SBO DGs being available.

9. The availability of AAC or supplemental power source shall be checked every 8-12 hours (once per shift).

   WCNOC Implementation: TS Required Action B.2 requires the verification of the availability of the SBO DGs initially within 1 hour then once per 8 hours thereafter.

10. If the AAC or supplemental power source becomes unavailable any time during extended AOT, the unit shall enter the LCO and start shutting down within 24 hours.

    WCNOC Implementation: The second Completion Time for TS Required Action C.1 specifies that if a required SBO DG unavailability occurs sometime after 48 hours of continuous DG inoperability, then the remaining time to restore the unavailable SBO DG to available status or to restore the DG to operable status is limited to 24 hours. If two SBO DGs are not available or the DG cannot be restored to operable status then TS Condition H would be entered and a plant shutdown initiated.

11. The staff expects that the licensee will provide the following Regulatory Commitments:

    a) The extended AOT will be used no more than once in a 24-month period (or refueling interval) on a per diesel basis to perform EDG maintenance activities, or any major maintenance on offsite power transformer and bus.

    WCNOC Implementation: Attachment VIII provides a commitment to ensure the extended Completion Time will be used no more than once in an 18-month period (a refueling interval) on a per DG basis to perform DG planned maintenance activities. No limit is placed on the use of the extended Completion Time for an unplanned removal of a DG from service and the corrective maintenance to restore operability.

    b) The preplanned maintenance will not be scheduled if severe weather conditions are anticipated.

    WCNOC Implementation: This activity has been implemented at WCGS through the TS Bases and procedure SYS KJ-200, "Inoperable Emergency Diesel."

    c) The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended AOT.

    WCNOC Implementation: Plant procedures provide the guidance for communications between the Transmission System Operator and control room operators on the status of the plant and the transmission system when a DG is taken out of service. See the discussion in Attachment I, Section 3.7. Attachment VIII provides a commitment to revise plant procedures to include daily communications between the Transmission System Operator and control room operators on the status of the plant and the transmission system when a DG is taken out of service

    d) Component testing or maintenance of safety systems and important non safety equipment in the offsite power systems that can increase the likelihood of a plant transient (unit trip) or LOOP will be avoided. In addition, no discretionary switchyard maintenance will be performed.

    WCNOC Implementation: This activity has been implemented through the TS Bases and procedure AP 22C-003, "On-Line Nuclear Safety and Generation Risk Assessment."

e) TS required systems, subsystems, trains, components, and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components, and devices.

WCNOC Implementation: This activity is already in place at WCGS. Refer to Attachment I, Section 3.7.

f) Steam-driven emergency feed water pump(s) in case of PWR units, and Reactor Core Isolation Cooling and High Pressure Coolant Injection systems in case of BWR units, will be controlled as “protected equipment.”

WCNOC Implementation: Procedures AP 22C-003 and AI 22C-013, “Protected Equipment Program,” identify the protected equipment during the use of an extended DG Completion Time.

For the commitments listed in Attachment VIII, WCNOC plans on placing this information in plant procedures that provides the contingency actions to be taken for a planned or unplanned DG Outage.